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BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 ET SEQ.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. RE-00000C-94-0165 **NOTICE OF FILING STAFF'S TESTIMONY**

Staff of the Arizona Corporation Commission hereby files testimony of Ray T. Williamson and Lee Smith in the above-captioned dockets.

RESPECTFULLY SUBMITTED this 30th day of June 1999.

By: Paul A. Bullis
Paul A. Bullis
Christopher C. Kempley
Janice M. Alward
Janet Wagner

Arizona Corporation Commission
DOCKETED
JUN 30 1999
DOCKETED BY

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By

DIRECT

TESTIMONY OF

RAY T. WILLIAMSON

AND

LEE SMITH, CONSULTANT
LA CAPRA ASSOCIATES

DOCKET NOS. E-01345A-98-0473
E-01345A-97-0773
RE-00000C-94-0165

JUNE 30, 1999

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
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WILLIAM A. MUNDELL
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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
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DIRECT

TESTIMONY

OF

RAY T WILLIAMSON

ACTING DIRECTOR

UTILITIES DIVISION

JUNE 30, 1999

I. INTRODUCTION

Q. Please state your name and business address for the record.

A. My name is Ray T. Williamson. My business address is the Arizona Corporation Commission (Commission or ACC), 1200 West Washington, Phoenix, Arizona 85007.

Q. What is your position at the Commission?

A. I am Acting Director of the Utilities Division.

Q. Prior to becoming Acting Director, where were you employed?

A. I have been employed at the Commission since 1992 in various positions, including Economist, Senior Rate Analyst and Chief of Economics and Research.

Q. Please describe the balance of your background and experience?

A. My statement of Professional Qualifications is appended to this testimony as Schedule RTW-2.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's concerns and recommendations related to Commission review and approval of the proposed Arizona Public Service Company Settlement Agreement ("Settlement").

II. APPROVAL OF THE SETTLEMENT

Q. Does Staff recommend approval of the Settlement?

A. Yes. Staff recommends approval of the Settlement with certain limited modifications that Staff believes clarify the Settlement's provisions and enhance the opportunity for competition in the transition to a competitive market.

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Q. Why is Staff recommending approval of the Settlement?

A. Staff believes the proposed Settlement provides certainty and a known path to competition. Staff reviewed the Settlement within the public interest framework of balancing the Settlement's implications for competition in Arizona with the guaranteed rate reductions reflected in the Settlement. This balancing of interest included an evaluation of the immediate benefits of the Settlements' known rate reduction schedules with the Settlement's impact on establishing a truly competitive market that would provide greater future reductions due to competitive pricing pressures.

Q. Why would Staff support addressing the issues through a settlement rather than through evidentiary hearings on the individual issues?

A. Staff wants to foster the development of robust and meaningful competition at the earliest possible date. As a practical matter, if these issues are not addressed in a settlement, it is almost certain that competition would be slower to develop.

Without the resolution of the major issues included in a settlement, it is doubtful whether many competitors would offer service or whether many customers would risk signing a contract for competitive service. Issues such as stranded costs, competition transition charges, market generation credits, final unbundled tariffs and other issues are all matters necessary for competitors and customers to determine whether they will be able to forge a better deal than is available from Affected Utilities.

III. STAFF'S CLARIFICATIONS AND MODIFICATIONS

Q. What clarifications and modifications is Staff proposing to the Settlement?

A. In general terms, Staff's recommendations provide for greater unbundling of tariffs, increase the market generation credit, and clarify provisions concerning certain adjustor mechanisms referred to in the Settlement. These clarifications and modifications to the Settlement are the subject of Staff Witness Lee Smith's testimony.

Q. What are the implications of the direction that the Settlement has suggested for Arizona's competitive retail electric market?

A. The Settlement's implications are important to the eventual success of Arizona's Retail Electric Competition effort. When the Arizona effort to evaluate Retail Electric Competition commenced in 1994, the underlying principle was that competition among a wide range of competitors would drive down the price of electricity and electricity services in Arizona. This belief in the price-reducing forces of competitive action continues today.

However, the Settlement takes an approach that offers the parties that negotiated the settlement and others a specified schedule of rate reductions over time, while discouraging entry of competitors through the adoption of an implicit Market Generation Credit that will not attract competitors to Arizona. As proposed, the Settlement appears to favor guaranteed rate reductions over the establishment of a competitive market during the transition to competition. Staff believes the Commission should do more than approve a Settlement that guarantees a certain level of rate reductions, and in addition, establish a robust competitive market that may well surpass the rate reductions in the settlement as well as encourage the innovation and cost-reducing behavior of dozens or, possibly, hundreds of competitors. This Settlement will accomplish both of these goals if Staff's modifications to the Settlement as outlined in Ms. Smith's testimony are adopted by the Commission.

Q. Why do you believe that the Settlement requires Staff's modifications to encourage a truly competitive market?

Evidence from other States has shown that the manner in which state Public Utility Commission's structure the competitive market has a major impact on how both customers and competitors will react in those markets. For instance, in January 1998, California chose to require a 10% rate reduction for all customers. This took the incentive out of the customer choice. With no risk, most customers merely decided to stay with their utility and receive the automatic 10% reduction. In both California and Massachusetts, the Market Generation Credits were too low to encourage competitors, so few competitors are active in those States and a relatively small number of customers have switched suppliers. According to Staff Witness Lee Smith's testimony, the implicit Market Generation Credit is too low for some customers to be able to make a competitive choice. In addition, Ms. Smith has also concluded that there will be little if any competition for APS metering and billing services due to the Agreement adopting a significantly lower avoided cost credit rather than embedded cost for these services.

IV. IMPACT ON APS' CUSTOMERS

Q. Is this Settlement a good deal for the customers of APS?

A. It appears so. The purpose of moving toward retail electric competition is to allow customer choice and lower rates in a changing market structure. The Settlement Agreement allows all customers, whether eligible for competition or not, to get lower rates starting in 1999. This is particularly important for those customers who are unable to switch suppliers and for those whom the competitors may not be interested in serving. Let's take low-income residential customers, for instance. In the filings that the Commission Staff has seen so far, few competitors are planning on targeting residential customers. Even if those customers are eligible to exercise choice, there may not be many competitors willing to offer them service. In a free market, the competitors can choose to sell to any customers that they wish, or choose not to sell to certain customers. It is entirely possible that competitors may decide to by-pass low-income customers completely. If that is the case, this Settlement will ensure that low-income customers of APS will see rate reductions in the coming years, whether they choose another supplier or not.

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Q. Do you have any reservations about this "good deal"?

A. As I have indicated in my previous comments, the series of rate reductions in the settlement may be less than that which might have resulted from a more competitive environment resulting from a higher implicit Market Generation Credit. Ms. Smith also discusses this point in her testimony.

Q. Is this a better deal than could be obtained without the Settlement?

A. It is uncertain whether a better deal could be obtained without the Settlement. One of the benefits of the Settlement is that it brings immediate and quantifiable benefits to ratepayers, rather than requiring ratepayers to wait an indefinite length of time for benefits that may or may not be greater than those contained in the Settlement. In addition, the Settlement provides certainty, resolves issues, and establishes a path for competition in APS' service territory. The Settlement allows us to put many contentious issues behind us and focus on bringing competition to APS' customers.

V. COMMISSION APPROVALS AND REQUESTED WAIVERS

Q. Are there any Commission approvals inherent in the body of the Proposed Settlement Agreement with which the Staff has concerns?

A. Yes. In Article IV, Section 4.3, the Proposed Settlement contains language pursuant to Arizona Revised Statutes ("A.R.S.") § 40-202(L) that effectively exempts the provision of competitive services by APS and any of its affiliates from regulation as public service corporations. Also in Article IV, Section 4.5, approval by the Commission of the Proposed Settlement constitutes waivers to APS and its affiliates (including its parent) of the Commission's existing affiliated interest rules (A.A.C. R14-2-801, *et.seq.*).

Q. Please state A.R.S. § 40-202(L) for clarification.

A. A.R.S. § 40-202(L) states "[t]he commission by rule or order may exempt or partially exempt any competitive service of any public service corporation from the application of

§ 40-203, § 40-204, subsections A and B and §§ 40-248, 40-250,40-251, 40-285, 40-301, 40-302, 40-303, 40-321, 40-322, 40-331, 40-332, 40-334, 40-365, 40-366, 40-367, 40-374, and 40-401."

Q. Does the Proposed Settlement include all of the above A.R.S. sections?

A. No. A.R.S. § 40-374 is not included in the Proposed Settlement but Staff is not aware of the reason for the exclusion.

Q. Is it Staff's recommendation that the exemptions contained in the Proposed Settlement are inappropriate and should be explicitly denied?

A. No. Staff is recommending that the Commission reserve its approval of the exemptions until such time as the applicability of the statutes to competitive services can be evaluated on an industry-wide basis versus a blanket exemption for APS and its affiliates exclusively.

Q. What is the basis for Staff's recommendation to reserve approval of the exemptions?

A. If the Commission chooses to allow these exemptions, it should be after a complete analysis of the impact of its decision on the development of a competitive market and all affected participants. In addition, this exemption for APS and its affiliates should not provide the vehicle for similar blanket exemptions by other competitive service providers without the benefit of prior analysis of the issues by the Staff and the Commission.

Q. What is Staff's recommendation regarding the requested waivers from the existing affiliate interest rules?

A. Staff is recommending that the Commission adopt the language from the Settlement Agreement that Staff reached with APS in November 1998 as it relates to the requested waivers from the existing affiliated interest rules. The waivers from the existing affiliate interest rules were evaluated in depth by Staff in relation to the November Settlement

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agreement which was subsequently withdrawn. The evaluation resulted in the granting or limiting of some of the requested waivers and are summarized in Exhibit RTW-1. Staff would point out the importance of specifically limiting the request to waive A.A.C. R14-2-804 (A) that requires any affiliate that transacts business with the Utility Distribution Company to open its books and records to Commission review. This request should be viewed in tandem with the Settlement's language regarding Exempt Wholesale Generator status, specifically the "specific determination" appearing at the top of page 7 of the proposed Settlement which states "[t]he Commission has sufficient regulatory authority, resources and <u>access to the books and records of APS and any relevant associate, affiliate, or subsidiary company</u> to exercise its duties under Section 32(k) of PUHCA." (emphasis added).

VI. CONCLUSION

Q. In light of the above, what is Staff's final recommendation?

A. The Commission should approve the Settlement as clarified and modified by Staff.

Q. How would you propose that the Settlement Agreement be modified to address the problems you have outlined above?

A. The Agreement needs to be modified to provide a better balance between the goal of guaranteed rate reductions and the goal of a truly competitive market for retail electric services. This balance can be achieved in a number of different ways. The key to achieving a better balance is to raise the Market Generation Credit and the metering and billing credits to a level where all customer classes will have the opportunity to make a competitive choice as explained further in Ms. Smith's testimony. The cost of raising these credits can be recovered through a higher Competitive Transition Charge (CTC), a longer recovery period for the CTC, lower rate reductions or some combination of these three. In conclusion, the Commission should not sacrifice the goal of having a competitive market for guaranteed rate reductions.

Q. If all of Staff's clarifications and modifications are not adopted by the Commission, does Staff believe the Commission should approve the Settlement as proposed?

A. Yes, however Staff has reservations as to the Settlement's impact on competition, particularly during the transition period provided for the recovery of stranded cost. Once stranded cost is fully recovered by APS, the basis for approval of the Settlement becomes more compelling. In other words, when stranded cost is collected, the value of the certainty and known path to competition reflected in the Settlement is increased.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBIT RTW-1

Staff's recommended conditions and limitations for waivers under the following Affiliated Interest Rules:

- **R14-2-801(5)**

  APS has requested a waiver of the definition of "reorganization" to exclude corporate reorganizations that do not involve a reconfiguration of the UDC in the holding company structure. Under the waiver proposed by APS, the holding company would be free to reorganize, buy or sell non-regulated affiliates without Commission approval. The Commission agrees that R14-2-801(5) is waived as applied to APS' non-regulated affiliates to the extent that the UDC is not implicated in any reorganization of the holding company's structure or the non-regulated affiliates' structure. In any reorganization where the UDC is implicated in any manner as to reconfiguration of the holding company's structure or an affiliates' reconfiguration, or if the UDC forms, divests or reconfigures any of its subsidiaries, Rule R14-2-801(5) is not waived and is applicable to APS (UDC).

- **R14-2-804(A)**

  APS has requested a waiver of the rule that requires any affiliate that transacts business with the UDC to open its books and records to Commission review. The Commission agrees that R14-2-804(A) may be waived as long as the non-regulated affiliate's books and records reflect transactions with the UDC and are included in the Code of Conduct required by the Electric Competition Rules. By this waiver, the Commission still retains jurisdiction to review and have access to the books and records of affiliates of the UDC for whatever purposes the Commission deems appropriate if the Commission's rate setting jurisdiction is implicated.

- **R14-2-805(A)**

  APS has requested waiver of the rule that requires a holding company to file an annual report with respect to diversification plans and the activities of unregulated subsidiaries. The affect of the waiver requested by APS would be to limit the annual filing requirement to the UDC only. The Commission agrees that the annual filing under the rule can be limited to the UDC unless the holding company or subsidiary's activities implicate the UDC, and have a likely material adverse affect upon the UDC's financial viability and integrity.

- **R14-2-805(A)(2)**

  This Rule requires a specific description of business activities of all affiliates to be filed with the Commission on an annual basis. APS wishes to have a waiver of the Rule and limit disclosure to the nature of the business rather than specific activities. Staff agrees this Rule may be waived to the extent indicated by APS.

- **R14-2-805(A)(6)**

APS seeks a waiver of the disclosure requirement in the annual filing for bases for allocation of all plant revenue expenses to all regulated and unregulated entities in the holding company structure. APS' request limits disclosure to allocations applicable to the UDC. Staff agrees with this waiver to disclosure but reserves the Commission's jurisdiction to receive disclosure of the bases for allocation if necessary in the Commission's determinations in any matter, including but not limited to rate setting matters.

- **R14-2-805(A)(9), (10) and (11)**

APS seeks a waiver of the annual submission of contracts and agreements for transactions between the regulated utility and nonregulated affiliate. Staff agrees to the waiver of this requirement as requested by APS as to the contracts and agreements which are not covered by the Code of Conduct required by the Retail Competition Rules or not subject to FERC approval. However, the Commission reserves the jurisdiction to receive the information that would have been submitted under the rule, if the Commission deems necessary for any purpose including, but not limited to rate setting matters.

EXHIBIT RTW-2

RAY T. WILLIAMSON

STATEMENT OF PROFESSIONAL QUALIFICATIONS

EDUCATION:

M.B.A. (Finance)	Arizona State University, Tempe, AZ, 1982
M.P.S. (Public Administration)	Western Kentucky University, Bowling Green, KY, 1976
B.S. (Engineering)	U.S. Military Academy, West Point, NY, 1970

PROFESSIONAL DESIGNATIONS:

Certified Energy Manager (CEM), Association of Energy Engineers, 1984

CURRENT PROFESSIONAL ACTIVITIES:

- Chairman, Solar Electricity Division, American Solar Energy Society
- Member, Association of Energy Engineers
- Member, International Association for Energy Economics
- Member, American Solar Energy Society

PAST PROFESSIONAL ACTIVITIES:

- Member, Board of Directors, Solar Rating & Certification Corporation (SRCC), 1988-91; Treasurer, 1989; Secretary, 1990
- Member, Rating Methodology Committee of SRCC, 1981-84
- Member, Arizona Photovoltaic Applications Task Force, 1985-86
- Participant, Arizona Energy Policy & Plan Development, 1989-90
- State Representative, Western Regional Biomass Energy Program, 1988-91
- Member, Arizona Electric Vehicle Task Force, 1991-92
- Member, Executive Committee, Interstate Solar Coordination Council, 1991-92
- Member, Externalities Task Force of the Arizona Corporation Commission, 1992
- Member, Environmental Technology Industry Cluster, Governor's Strategic Partnership for Economic Development (GSPED), 1992
- Member, Executive Committee, Interstate Renewable Energy Council, 1994-95
- Member, National Photovoltaics for Utilities Steering Committee, 1994-95
- Ex Officio Member, Planning Committee, Southwest Regional Transmission Association (SWRTA)

TEAM LEADERSHIP AND COMMITTEE COORDINATION EXPERIENCE:

- Coordinator, Arizona Electric System Reliability and Safety Working Group, 1996-98
- Coordinator, Arizona Photovoltaics for Utilities Cooperative, 1993-present
- Co-founder & Coordinator, Arizona Electric Vehicle Enterprise Network, 1990-92
- Founder & Chairman, Air Quality/Alternative Fuels Task Force of Phoenix Futures Forum, 1990-1992
- Coordinator, Externalities Prioritization Working Group, 1993-4
- Coordinator, Arizona Renewables Working Group, 1994-95
- Leader, Energy Efficiency & Environment Task Force, Retail Electric Competition Working Group, 1994-95

EXHIBIT RTW-2

PROFESSIONAL EXPERIENCE:

ARIZONA CORPORATION COMMISSION, PHOENIX, AZ (OCT '92 - PRESENT)

ACTING DIRECTOR, UTILITIES DIVISION, MAR '98-PRESENT:

- Manages the 95-person Utilities Division
- Directly supervises five Section Chiefs, two Supervisors, and an Assistant Director

CHIEF, ECONOMICS AND RESEARCH, JUNE '97 –MAR '98:

- Managed the Economics and Research Section of the Utilities Division
- Supervised a staff of seven professionals
- Read, reviewed, edited, and approved tariffs, special contracts and other Commission Open Meeting items
- Prepared testimony for lawsuits regarding Retail Electric Competition
- Coordinated the Electric System Reliability and Safety Working Group
- Coordinated the Solar Portfolio Standard Subcommittee
- Staffed the Unbundled Services and Standard Offer Working Group
- Staffed the Independent System Operator and Spot Market Development Working Group
- Coordinated the overall Retail Electric Competition effort for the Division
- Wrote, edited, and published the Solar Portfolio Standard Subcommittee's final report
- Co-wrote, edited, and published the Unbundled Services and Standard Offer Working Group's final report
- From 12/15/97-2/6/98 performed duties of Acting Director for four weeks while Director was out of the country

SENIOR RATE ANALYST, MAY '94 - JUNE '97:

- Specialized in electric utility regulation activities and projects, including integrated resource planning, externalities, renewable energy resources, retail electric competition, and electric tariff review and evaluation
- Evaluated and developed recommendations on utility renewable energy plans and projects
- Served as the group leader of the Arizona Photovoltaics for Utilities Cooperative
- Coordinated the activities of the collaborative Renewables Working Group
- Wrote draft Commission rules for externalities and integrated resource planning
- Served as the Task Force Leader of the Energy Efficiency and Environment Task Force in the Retail Electric Competition Working Group
- Helped draft proposed Commission Retail Electric Competition Rules
- Participated as a member of the Planning Committee of the Southwest Regional Transmission Association
- Acted as the Coordinator of Arizona's Electric System Reliability and Safety Working Group

ECONOMIST, OCT '92 - MAY 94:

- Conducted economic and policy analyses of electric and telecommunications utility issues
- Analyzed applications of utilities regarding rate levels, rate design, and service offerings
- Prepared recommendations and testimony on renewable energy, energy conservation, demand-side management, integrated resource planning, special rates and contracts, and tariff filings
- Served as the Coordinator of the Arizona Photovoltaics for Utilities Cooperative
- Served as the Coordinator of the Externalities Prioritization Working Group
- Wrote, edited, and published the Externalities Prioritization Working Group's final report

EXHIBIT RTW-2

ARIZONA DEPARTMENT OF COMMERCE, PHOENIX, AZ (JULY '85 - OCT '92)

ENERGY BUSINESS TECHNICAL SPECIALIST in the **ARIZONA ENERGY OFFICE**, MARCH '90 - OCT '92:

- Prepared testimony and testified as an expert witness in the first cycle of the Corporation Commission's Integrated Resource Planning. The testimony resulted in the formation of two Commission Task Forces to consider externalities and sliding-scale hook-up fees.
- Participated in the two-year Arizona Energy Policy and Plan development program
- Founded the collaborative Arizona Photovoltaics for Utilities Cooperative and coordinated its activities

MANAGER of the **ARIZONA SOLAR ENERGY OFFICE**, JULY '87 - MARCH '90:

- Managed the entire solar energy program for the State of Arizona
- Managed the accomplishments of a staff of eight employees and numerous contractors and subcontractors

ENERGY ECONOMIC ANALYST of the **ARIZONA ENERGY OFFICE**, JULY '85 - JUNE '87:

- Prepared various economic analyses, including the impact of the 1986 oil price decline
- Performed utility rate analyses and presented utility bill seminars to school officials and local governments
- Served on the Arizona Photovoltaic Applications Task Force established to evaluate the potential for the use of photovoltaics in Arizona and to make recommendations to the Arizona Corporation Commission

ARIZONA SOLAR ENERGY COMMISSION, PHOENIX, AZ (DEC '80 - JUNE '85)

ASSOCIATE DIRECTOR, FEDERAL PROGRAMS MANAGER, & SOLAR ENGINEERING SPECIALIST:

- Developed strategies and marketing plans to enhance the commercialization of solar energy products
- Was responsible for revising, drafting, staffing, and coordinating work on Commission rules and the public hearings on rules

RAMADA ENERGY SYSTEMS, INC., TEMPE, AZ (JUNE '79 - JULY '80)

MANAGER, MARKETING SERVICES:

- Managed all services and support of the Marketing Department and of the company distribution network
- Established office administration programs, developed standard operating procedures for the Marketing Department, and initiated a comprehensive national inquiry response program
- Developed and implemented advertising, publicity and public awareness plans

SOLARON CORPORATION, DENVER, CO (JULY '76 - JUNE '79)

FEDERAL PROGRAMS ADMINISTRATOR, AUG '78 - JUNE '79:

- Managed all activities of the federal solar grant programs
- Wrote grant applications, assisted applicants with design and grant preparation, follow-up reporting, and assistance on winning grants

ASSISTANT TO THE MANAGER, DISTRIBUTOR SALES, SEP '77 - JUL '78:

- Responsible for the day-to-day activities of the distributor network for Solaron products
- Developed marketing plans for the distributor network
- Assisted distributors in project design, computer simulation, and equipment selection

MARKETING ADMINISTRATOR, JUL '76 - AUG '77:

- Coordinated office administration
- Provided training and grant application preparation assistance to customers in federal grant programs. Sales through these grant programs accounted for 26 percent of all 1977 Solaron sales
- Served as a sales engineer, designing and selling individual systems in areas without distributors and sales to walk-in customers

U.S. ARMY EXPERIENCE: Commissioned Officer from June 1970-January 1976

ADDITIONAL TRAINING:

1984-1993 Arizona State University, College of Business: 36 semester hours of economics courses. This included course work in public utility economics & finance.

1976-1996 Attendance at 110+ seminars, conferences and workshops covering subjects such as: electric industry restructuring, energy conservation, demand-side management, thermal storage, energy economics, financing of energy projects, cogeneration, solar energy, integrated resource planning, solar energy in utilities, environmental concerns, electric vehicles, biomass, and energy-conserving building design.

PUBLICATIONS

Williamson, Ray T. "The Versatile Transparent Polymer Collector." Paper presented at the 1980 Annual Meeting of the International Solar Energy Society, Phoenix, Arizona.

Williamson, Ray T. **Standards for Solar Devices**. Arizona Solar Energy Commission, May 1981.

Williamson, Ray T., Editor. **Information Sources for the Solar Industry**. Arizona Solar Energy Commission, May 1981.

Williamson, Ray T., Editor. **Licensing Solar Contractors in Arizona**. Arizona Solar Energy Commission, May 1981.

Williamson, Ray T., Editor. **Arizona's Solar Laws & Rules**. Arizona Solar Energy Commission, May 1981.

Williamson, Ray T., Editor. **Arizona's Solar Energy Tax Credits**. Arizona Solar Energy Commission, May 1981. "Standards for Solar Collectors." Arizona Solar Energy Commission, March 1982.

Williamson, Ray T. "Tax Credits for Photovoltaic Devices." Arizona Solar Energy Commission, March 1983.

Williamson, Ray T. **Standards for Solar Energy Devices in Arizona**. Arizona Solar Energy Commission, May 1983. "Standards for System Testing." AZ Solar Energy Commission, June 1983.

Williamson, Ray T., Richard Griswold and Frank Mancini. "Solar Energy Response Vehicle (SERV) Meets Emergency Needs." Paper presented at the 1991 Solar World Congress. **Proceedings of the Biennial Congress of the International Solar Energy Society**, Denver, Colorado, 19-23 August 1991.

EXHIBIT RTW-2

Williamson, Ray T., Doran Dalton and Robert Robin. "The Hopi Foundation's Solar Electric Enterprise: A Model for Renewable Industry Development in Developing Nations." Paper presented at the 1991 Solar Word Congress. **Proceedings of the Biennial Congress of the International Solar Energy Society**, Denver, Colorado, 19-23 August 1991.

Williamson, Ray T., Peter Eckert, Tom Lepley, and Frank Mancini. "Testing and Evaluation of a Mobile Photovoltaic/Genset Hybrid System." Paper presented at the 22nd IEEE Photovoltaic Specialist Conference. **Proceedings of the 22nd Institute of Electrical and Electronics Engineers, Inc. Photovoltaic Specialists Conference**, Las Vegas, Nevada, 7-11 October 1991.

Williamson, Ray T., Editor/Co-author, and Robert Hammond, Frank Mancini, and James Arwood. "The Solar Electric Option (Instead of Power Line Extension)." A 16-page brochure published by the Arizona Corporation Commission and the Arizona Department of Commerce. Phoenix, Arizona, August 1993.

Williamson, Ray T., Co-author, and Staff of Economics & Research Section, Arizona Corporation Commission. "Staff Report on Resource Planning." Arizona Corporation Commission, September 1993.

Williamson, Ray T. "Staff Report on Arizona Public Service Company's Carol Spring Mountain Project," (DocketNo. U-1345-94-335), Arizona Corporation Commission, October 1994.

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BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
WILLIAM A. MUNDELL
Commissioner

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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS PLAN FOR STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 ET SEQ.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. RE-00000C-94-0165

DIRECT

TESTIMONY

OF

LEE SMITH

CONSULTANT

LA CAPRA ASSOCIATES
BOSTON, MASSACHUSETTS

JUNE 30, 1999

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APPENDICES

INTRODUCTION

Q. What is your name and business address?

A. My name is Lee Smith, and I work for La Capra Associates, 333 Washington Street, Boston, Massachusetts.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Arizona Corporation Commission (Commission) Staff.

Q. Please describe your background and experience.

A. I am a Senior Economist at La Capra Associates. I have been with this energy planning and regulatory economics firm for 15 years. Prior to my employment at La Capra Associates, I was Director of Rates and Research, in charge of gas, electric, and water rates, at the Massachusetts Department of Public Utilities. Prior to that period, I taught economics at the college level. My resume is attached as Exhibit LS-1.

Q. What is the purpose of your testimony?

A. I am testifying as to the concepts in the 10 Page Settlement Agreement between Arizona Public Service Company ("APS" or "Company") and the Residential Utility Consumer Office ("RUCO"), Arizona Community Action Association ("ACAA"), and Arizonans for Electric Choice in Competition ("AECC") excluding Enron ("Proposed Settlement").

Q. Have you submitted testimony previously in this proceeding?

A. Yes. I submitted testimony on the proposed November 4, 1998 Settlement between APS and the Commission Staff which was subsequently withdrawn ("November Settlement").

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Q. What major changes should be made in the regulation and organization of the electric industry to foster the development of a competitive electric services market?

A. In order to have competition in electric services, the following must occur

- assurance that all potential suppliers have fair access to customers;
- assurance that all potential suppliers have fair access to the wires;
- the ability to identify and address market power in generation;
- customers must have the opportunity to purchase electric services from a supplier of their choice;
- customers must be informed of what they pay the utility for each service, so they can compare different providers;
- subsidization of unregulated services by regulated services must be avoided, otherwise the utility will have an unfair advantage over competitive suppliers; and
- disputes over stranded cost must be resolved.

Q. What criteria should be applied in considering approval of the APS settlement?

A. It is Staff's opinion that any settlement agreement presented to the Commission should be evaluated using the above-mentioned criteria. The Commission should apply criteria that measure whether the agreement contributes to the goals of allowing competition and providing benefits to Arizona consumers. An approved Settlement should facilitate the development of a competitive market in Arizona. That requires the characteristics described above. It should also provide all customers with some immediate benefits that they would not receive under a continuation of existing regulatory practices.

Q. Does the Proposed Settlement ensure that all potential suppliers have fair access to customers?

A. The Proposed Settlement is consistent with the Electric Competition Rules ("Rules") as they relate to providing fair access to customers by the Affected Utilities as reflected in Article VII, Section 7.7. The Commission will have the authority to ensure equal access by all potential suppliers to the customers through its approval of the Code of Conduct contemplated by the Rules and referred to in the Proposed Settlement at Article VII, Section 7.7. Based upon the foregoing, it is Staff's opinion that the Proposed Settlement adequately ensures that all potential suppliers will have fair access to customers.

Q. Does the Proposed Settlement ensure that all potential suppliers have fair access to the wires?

A. The support by APS of the Arizona Independent Scheduling Administrator (AISA) and of the formation of the Desert Star Independent System Operator (ISO) is an important step in providing fair access to the wires. However, as long as a single entity owns and controls transmission and owns generation there will be incentive for and possibility of limiting access of other suppliers to the wires.

Q. Does the Proposed Settlement enable the Commission to identify and address generation market power?

A. The Proposed Settlement requires that APS sell its generating assets to an affiliate at the net book value of those assets in 2002. I have some concerns about the continuing incentives for APS, as the only provider of transmission service, to favor standard offer power purchases or delivery of generation from an affiliate. In its recent FERC Notice of Proposed Inquiry regarding Regional Transmission Organizations ("RTO"), FERC expresses concerns that the existing utility-by-utility control of transmission is not efficient and may allow a transmission owner to favor its own generation, in spite of the rules about Open Access Transmission Tariffs established in FERC Order 888.

Q. What impact may the FERC proceeding have on the APS Proposed Settlement and the proposed transfer of generating assets to an affiliate?

A. In the time between now and when APS transfers its assets, FERC should have completed the RTO investigation, and there will have been adequate time for Desert Star or some other type of an RTO to be in operation or fully developed conceptually. I would recommend that the Commission's approval of the generation transfer in the Proposed Settlement be conditioned upon appropriate progress toward an RTO. The establishment of an RTO has the potential of greatly alleviating, if not eliminating, concerns about both vertical and horizontal market power.

Q. Does the Proposed Settlement provide customers the opportunity to purchase electric services from a supplier of their choice?

A. Article I of the Proposed Settlement, Implementation of Retail Access, addresses providing customers the opportunity to purchase electric services from a supplier of choice. The Proposed Settlement accelerates the implementation date and increases the eligible load from the amounts required in the Electric Competition Rules. Based upon the foregoing, it is Staff's opinion that the Proposed Settlement provides customers the opportunity to purchase electric services from a supplier of their choice.

Q. Does the Proposed Settlement inform customers what they pay the utility for each service, so they can compare different providers?

A. No. The Company has not unbundled its Standard Offer Service tariffs, and has not informed Direct Access customers how much they would have paid the Company for generation. In addition, the unbundled metering and billing credits in the Proposed Settlement do not reflect the embedded cost that a customer is currently paying for these services.

Q. Does the Proposed Settlement contain adequate safeguards to avoid the subsidization of unregulated services by regulated services, so as to avoid giving the utility an unfair advantage over competitive suppliers?

A. Consistent with the Electric Competition Rules, the Proposed Settlement contemplates the filing of a Company-specific code of conduct. The Code of Conduct is subject to the

Commission's approval of terms that should establish procedures to eliminate the potential for the subsidization of unregulated services by regulated services. Based upon the foregoing, it is Staff's opinion that the Proposed Settlement contains appropriate language to allow the Commission to approve a Code of Conduct, consistent with the Rules, to provide adequate safeguards to avoid the subsidization of unregulated services by regulated services, so as to avoid giving the utility an unfair advantage over competitive suppliers.

Q. Does the Proposed Settlement resolve disputes over stranded cost?

A. The Proposed Settlement attempts to resolve disputes over stranded costs.

Q. Please explain how the Settlement attempts to resolve the issue of stranded costs.

A. The Proposed Settlement at Article III - Regulatory Assets and Stranded Costs provides a quantification of stranded costs and establishes a recovery mechanism for a portion of the amount determined. It contains an assertion that allowable stranded costs are at least $533 million after mitigation (Section 3.2).

Q. Do you agree with this assertion about the value of stranded costs?

A. No. Mr. Davis cites Exhibit 2, presented to the Commission in this docket at Exhibit JED-3. This exhibit most certainly does not reflect a full and fair evaluation of stranded costs. It compares market revenues to embedded generation costs for the six years commencing in 1998 and ending in 2004.

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DETAILED DISCUSSION OF SPECIFIC PROBLEMS WITH CRITERIA

Q. Of your recommended criteria to be used by the Commission in evaluating a settlement associated with competition in electric services, you have identified two which are not fully met by the Proposed Settlement: 1) informing customers what they pay the utility for each service, so they can compare different providers, and 2) resolving disputes over stranded costs. Would you please explain more precisely why you believe the first of these criteria have not been met.

A. Yes. The Company has not provided rates which unbundle the existing tariffs. With regard to metering and billing services, if a customer chooses an alternate supplier of metering or billing services or both, the Company proposes to provide credits to the bill. These credits are based on APS' avoided costs only. They reflect decremental costs associated with these services, but do not include all embedded costs.

Q. What alternative would be consistent with the criteria?

A. The Company calculated and offered rates in the November Settlement based on its unbundled cost of service study. The credits were significantly higher than the avoided cost credits in this Proposed Settlement. For instance, for Residential customers the billing credit was $1.33 per month, while in the Proposed Settlement the billing credit is only $.30 per month. For Extra-large General Service customers, the embedded metering credit was $154.15 per month, while the avoided cost credit proposed in the Proposed Settlement is only $55 per month. The Company should file rates based upon the embedded costs unbundled into functional components.

Q. Would you explain how the use of avoided costs versus embedded costs will inhibit the development of a competitive market for metering and billing services?

A. Yes. The Company is currently collecting revenues from ratepayers based on the embedded costs of all services, including metering and billing. However, if the customer does not use these services, the Company is proposing to reduce bills by a much smaller amount than what was collected in their current rates. This means that customers who choose alternative suppliers will continue paying for some portion of the Company's metering and billing costs. This type of pricing is also anti-competitive, in that new providers will find it difficult, if not impossible, to provide these services at a competitive rate. To take a specific example, the decremental cost rate, as proposed in the Proposed Settlement, would not include the cost of the meter reader's truck or any overhead. These expenses would be supported by the remaining distribution portion of the rate, while the new competitor would need trucks and overhead and have to recover these from his price.

Q. Are there any other ways in which the Proposed Settlement rates do not fully inform customers about their rates?

A. Yes. For each customer class, the Company provides one (or more) bundled Standard Offer Service tariff, which does not show separate functional rate components (generation, transmission, distribution, etc.), and one Direct Access tariff, which is unbundled into distribution service and Competitive Transition Charge ("CTC") components, but not generation or transmission.

Q. Can you explain why the unbundling of the Standard Offer Service tariffs to provide this level of detailed information is important to the development of a competitive market?

A. To make an informed decision about competitive service alternatives, customers must know what credit they will receive if they shop for generation, as well as metering and billing services, and those credits must be high enough so that some suppliers can compete with them. The Company's tariff does not inform customers of the market generation credit ("MGC") or the amount of transmission costs that they pay on Standard Offer service.[1] Customers will know the tariff rates that they will pay for bundled

[1] The rate reduction that customers receive for not buying generation is usually called the Market Generation Credit, or MGC.

service, and they will know the direct access tariff rates that they will pay if they choose an alternative supplier. However, they must compute the difference between the two in order to know what generation and transmission revenue target they must beat. This is not an easy comparison, and it differs for every customer. Without the ability to isolate the portion of the customer's bill associated with these services, an informed choice can not be made. It is imperative that the Company be required by the Commission to fully unbundle its Standard Offer Services tariffs and Direct Access tariff to the same level of detail to allow this comparison.

Q. What impact do you expect this lack of a transparent market generation credit will have on competition?

A. I expect that it will have a deleterious effect. The largest customers may make these computations, or marketers may make these computations for them, but it will be difficult for smaller customers to shop. The smaller customer, receiving information that an alternative supplier can provide power for twelve months for a price of x, does not know whether the average price he is paying for power is more or less than x. To make this determination, the customer will have to have available his billing history for the last twelve months, or project his bill determinants for the next year, and determine what his bill would be under two separate rate schedules, involving seasonal differentials, an energy block (or more complicated time-of-use blocks), and a change in the basic customer charge.

Q. Are there any other side effects of this "two rates per class" system?

A. Yes. The rate reductions to customers who choose will be different than the reductions to customers who do not choose. In some cases the reductions to choice customers will be greater than to bundled service customers.

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Q. How did you calculate the Company's proposed MGC for various classes?

A. The credit that Direct Access customers will receive for generation is the difference between the two sets of rates, the Standard Offer Service Tariff and the Direct Access Rate for their rate class. We have calculated the effective MGC from the Proposed Settlement rates for 1999-2000 to be approximately 3.0 cents for the Extra-Large General class, 4.1 cents for the General Service class, and 4.5 cents for the Residential class. The backup to the MGC calculations is attached to my testimony as Exhibit LS-2.

Q. Is this credit sufficiently large that alternative suppliers will be able to compete effectively with APS?

A. No. If an alternative supplier must pay more for generation, transmission, and required ancillary services than the credit which the customer will receive from the utility, we would expect that there would be very little if any competition. The supplier cannot compete if the price of his supply is higher than the credit that potential customers receive from APS.

Q. What market price measure have you examined to come to this conclusion?

A. Unfortunately, there is no single easily available reference price. We have estimated the wholesale market price from price information from the spot market in California. That estimation process is described in Appendix A. We estimate that the average wholesale market price for the last year has been 2.9 cents per kWh. To get power to the customer will also require accounting for line losses. In addition, the supplier must acquire ancillary services and transmission. This suggests that for a retail customer to have purchased all <u>predicted</u> energy needs from the California spot market, with minimum transmission costs and paying APS only for ancillary services and transmission, would have cost at least 3.4 cents per kWh for the Extra-Large General Service class, and considerably more for other classes.[2] I would expect that the price for 1999-2000 would

[2] For transmission prices, I have used the transmission rates in proposed tariffs submitted by APS in the November Settlement.

be slightly higher than this. However, I also expect that the actual retail market price of power will be still higher than the barebones spot market price.

Q. Please describe the other elements of market price.

A. First, customers, or their suppliers, must pay for "load balancing," risk of price variation, customer service, and some profit. These elements must be added to the wholesale price to determine what retail prices will be including a return on generating plant, and are probably buried in stranded costs. I believe a conservative estimate of retail prices would be 4.6 cents for Residential customers, 4.23 cents for General Service customers, and 3.45 cents for Extra-Large General Service customers. A more detailed discussion of these costs is contained in Appendix B.

Q. Might these be high measures of retail market price?

A. No. In fact, I believe it will be very difficult for alternative suppliers to match this price. This does not include any marketing or startup costs.

Q. The MGCs for the Residential class are much higher than for the Extra-Large General Service class. Are these credits likely to create competition for generation needs of the residential class?

A. No. First, the retail market price for the Residential class will be much higher for the residential class than for the Extra-Large General Service class, because of line losses, and load shape. Second, the residential market seems to be much less attractive to marketers than the large customer classes. Finally, only ten percent of the residential class will even be eligible for access, so the potential market is limited for two years.

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Q. Mr. Higgins testified that he expects that the MGC will be higher than the market price by about 5 mills, "for commercial customers". Why is his conclusion so different than yours?

A. Mr. Higgins is referring to a particular customer in the General Service class. Also, he is comparing the MGC to a wholesale price for absolutely flat load - in other words for a customer that used exactly the same kWhs every hour of every month. The customer for whom Mr. Higgins has calculated the commercial market generation credit does not have a flat load, since he has specified that this is a 55 percent load factor customer according to Response to Data Request LS-1. Recognizing that the wholesale price will be higher because of the customer's load shape would decrease the market generation credit.

Q. You stated earlier that you disagreed with the Company's assessment of its stranded costs. Do you agree with the market prices used by the Company in their stranded cost analysis?

A. No. They are too low by about 2 mills. We know that spot prices at Palo Verde for the eleven months from July 1998 through April 1999 were 2 mills, or 7 percent, higher than the prices used in the Company's stranded cost analysis for 1999. Moreover, the Company's generating units also earn revenue through the provision of ancillary services. That is, they sell not only energy but also ancillary services, which will produce additional revenues. Thus, the average revenue earned by the Company's generating units will be higher than the average wholesale price.

Q. Are there problems with the Company's analysis other than with the level of market prices projected?

A. Yes. The major problem is methodological. Even if the estimates of both market revenues and embedded costs were correct, the Company's presentation does not measure stranded costs. This methodology fails to reflect the true difference between market value and embedded costs.

Q. Why is this an incorrect method of measuring stranded costs?

A. The assets in question will continue to have value for longer than six years; in fact, most of the generating assets will continue in production for another ten to twenty years. As time passes, market prices increase, while embedded costs stay almost the same. Even the Company's brief analysis shows market prices increasing 6 mills as embedded costs increase by 1 mill. As a result, there will be a crossover point when these units produce market revenues in excess of embedded costs. From then on, the annual measurement of stranded cost will be negative. By stopping the analysis after six years, this methodology fails to account for future negative stranded costs.

The Company's witness, Mr. Landon, argues that stranded costs would actually be higher if the analysis encompassed more years. The test of this proposition would be for the Company to show their estimates of market and embedded prices in the long run. In response to discovery, the Company states that its estimates of market prices reach their embedded costs after 2008. Since the 1998 estimates showed market prices about 1 cent less than embedded costs, this indicates that market prices are projected to increase relative to embedded costs over the next 10 years. If this trend continues, it is clear that embedded costs will fall below market prices.

Q. Why do you expect market prices of generation to increase?

A. I expect that fuel prices will increase over time. Although there is considerable variation in fuel price projections, all of the forecasts that I have seen project that fuel prices will, in general, increase over time. Environmental rules are likely to increase generation prices, through requiring higher quality fuel or more expensive treatment of emissions. In addition, growth in energy demand is likely to mean more production by higher energy cost generating units.

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The capacity cost associated with generation is also likely to go up, as materials and labor costs increase. There has been an improvement in technology, which reduced capital costs, but it is not at all clear that capital costs can be continually decreasing. In fact, some of the apparent reduction in capital cost was due to the market situation of the manufacturers of generators.

Q. Mr. Landon also argues that the Company's estimate of its stranded cost may be low because it has assumed "aggressive" capacity factors for its coal and nuclear plants. Do you agree?

A. While I have not analyzed the Company embedded price projections in detail, the numbers that I have seen do not support this position. Mr. Landon compared projected capacity factors with only a few historic years, one of which was affected by an extraordinary event. Most utilities across the country have been increasing capacity factors in recent years as they have been making efforts to reduce costs in order to participate in competitive markets.

In addition, the Company used similar capacity factors in its modeling of embedded and market price. If we accepted Mr. Landon's view that the actual capacity factors for nuclear units will be lower than those projected, then embedded costs will be higher but so also will market prices. If nuclear units produce less energy, more energy must be produced from coal, gas and oil units, pushing up market prices.

Q. Since you expect that annual stranded costs will decrease and will become negative, do you agree that the Company has demonstrated stranded costs of $533 million?

A. I do not agree that the Company has appropriately demonstrated its level of stranded costs. I also do not agree that APS' stranded costs are $533 million. I think the correct number is materially less than this amount.

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RECOMMENDED REMEDIES TO PROBLEMS IDENTIFIED

Q. Of your recommended criteria to be used by the Commission in evaluating a settlement associated with competition in electric services, what are your recommendations for resolving the unsatisfied criteria, particularly 1) informing customers what they pay the utility for each service, so they can compare different providers, and 2) resolving disputes over stranded costs?

A. First, the Company should be required to remove the embedded costs of metering and billing from the distribution component of the Direct Access rates and show these as separate avoidable charges. They should be similar if not identical to the metering and billing charges included in the November Settlement. To address the remainder of the unsatisfied criterion regarding informing customers what they pay the utility for each service, so they can compare different providers, Staff recommends that the Commission approve the Proposed Settlement with the modified condition that APS unbundle its Standard Offer Service, showing generation and transmission rates. In addition, APS should provide explicit information on Market Generation Credits (MGC) for the Residential, General Service, and Extra-large General Service Direct Access rates. As for the second unsatisfied criterion, resolving disputes over stranded costs, Staff is recommending a true-up mechanism to prevent the over-collection of stranded costs which might occur without such a mechanism.

Q. How else should the Proposed Settlement be modified to create the potential for competition?

A. In order to create a competitive market, the market generation credits, particularly for the class most likely to shop, the Extra-Large General Service class, must be increased. The minimum MGC must be higher than the spot price adjusted for ancillary services and line losses. If the MGC is higher, either total rates will increase or some other component of rates must decrease. If another component of rates decreases, either the collection period must be lengthened or the total collection of revenues will be less than planned with the original rates. To accomplish this and still abide by other conditions of the settlement, at least two adjustments must be made. First, some other component of rates must be decreased by an equal amount. The logical choice is the CTC. Second, with a lower CTC, it will take a longer transition period to collect the same amount of stranded costs.

Q. How should the MGCs and CTCs be adjusted?

A. The goal should be to provide the Company with the same revenue collection as currently proposed from each class from the combination of the MGC and the CTC. With the proposed residual rather than stated MGC, if the CTC for any class is increased by a particular amount, the MGC is automatically decreased by the same amount. Since the proposed MGCs are about 2 mills lower than my estimated retail market price, I recommended that the CTCs be decreased by an average of about 2 mills in 1999 and 2000, which will increase the MGC by the same amount. In future years, the Proposed Settlement reduces charges for Direct Access, so that the MGCs increase, but are still lower than they should be. The Table below shows the MGCs in the Proposed Settlement and the MGCs which I am recommending for each year of the transition period. Again, an increase in an MGC can be accommodated by an equal decrease in the proposed CTC.

MARKET GENERATION CREDIT IN CENTS PER KWH

	1999	**2000**	**2001**	**2002**	**2003**	**2004**
Residential Settlement	4.5	4.6	4.7	4.7	4.7	4.9
Residential - CC Staff	4.6	4.6	4.7	4.7	4.8	4.8
General Service Settlement	4.1	4.1	4.2	4.3	4.3	4.5
General Service - CC Staff	4.2	4.2	4.3	4.3	4.4	4.4
Extra-Large GS Settlement	3.0	3.0	3.2	3.2	3.3	3.5
Extra-Large GS - CC Staff	3.3	3.3	3.4	3.4	3.5	3.5

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Q. In light of your disagreement with the Company's stranded cost claim, do you recommend that the Commission disapprove the settlement?

A. No. The Proposed Settlement will allow the Company to collect a level of stranded costs of $350 million, which is significantly lower than the claimed $533 million. It also clearly is an advantage to settle this very controversial issue. I recommend that the Proposed Settlement be modified so as to address both the MGC and the stranded cost questions. If the Company does not sell its generating assets, which would reveal their value, the best indications we have about the validity of their stranded cost estimate are actual market prices. Also, the MGC should ideally be related to actual market prices. I suggest the following modifications.

Earlier I advocated that CTCs should be reduced so that the MGC could be increased. The impact of this on CTC collection should depend upon whether the agreed upon MGCs appear to be a fair measure of the actual market prices.

The Company may accumulate in a deferred account the revenues that would have been collected through the higher proposed CTC. To determine if the CTC should continue beyond December 31, 2004, and for how long, the Company should make a filing with the Commission on July 1, 2004. This filing shall demonstrate the amount of CTC revenues collected and projected to be collected by December 31, 2004, and the resulting deferred CTC amount. In addition, this filing should compare the actual wholesale market price in 2003-2004[3], to the wholesale market price used as a basis for the company's stranded cost estimate for that year. If this actual market price is lower than the projected wholesale market price by more than one mill, the Company shall be allowed to continue collecting a CTC until the deferred amount and the full $350 million

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[3] The wholesale price would be determined by the California spot market price, unless an alternative source of transparent market information has been developed by that time.

is collected. If the actual market price is higher than the MGC by more than one mill, the Company shall not be allowed to collect the deferred amount, but shall be allowed to retain all previous CTC revenues collected.

In this latter case, we would have clear evidence that market prices had been considerably higher than those projected by the Company. Higher than projected market prices would strongly suggest that the Company's generating assets had more value than the Company had previously assumed.

To illustrate why I am advocating this deferral and conditional collection, we can refer to the Company's stranded cost filing. In the table below, I show how stranded costs would decrease if, in the year 2003, wholesale market prices increase by 1 mill from those projected by the Company in their stranded cost filing.

gWhs	Comp. estimate wholesale price cents/kWh	Embedded cost	Stranded cost	Hypothetical Actual wholesale price	Revised Stranded cost
23,400	3.2	3.8	$129 million	3.3	$105 million

Q. What is your final recommendation to the Commission regarding this agreement?

A. I am recommending that the Commission approve the Proposed Settlement with the minor modifications discussed above which will make the Proposed Settlement more consistent with the goal of establishing a competitive market.

OTHER ISSUES

Q. Are there any other rate issues?

A. Yes. Article 2.6 would require the Commission to approve four automatic adjustment clauses. The first and second clauses address Standard Offer costs after the Company has sold its generating assets, and will allow the Company to pass on the cost of acquiring that power. However, the third and fourth clauses will allow the Company to increase rates for certain costs, associated with implementation of the Electric Competition Rules and system benefits, without demonstration that overall Company earnings are less than allowed. This creates a situation similar to what has been described as a single issue rate case. The adjustment clause might identify that the Company had spent $30 million on transition costs, but since the issue would be examined in isolation, if sales growth had been rapid or other expenses had not increased much, the Company might have been overearning by $20 or $40 million. The fairer solution for ratepayers would be to award the Company only the $10 million shortfall in the first case, or to decrease rates in the second case.

Q. How could the Proposed Settlement be modified to address this issue?

A. The Proposed Settlement does not contain these clauses, but rather specifies that the Company file a detailed application for these clauses by June 1, 2002. The Commission would examine these clauses and "issue an order that shall also establish reasonable procedures pursuant to which . . . parties . . . may review the costs to be recovered." Those reasonable procedures could include an annual filing requirement that demonstrates that, absent the deferral, the Company would earn less than its authorized rate of return. The Commission could approve the Proposed Settlement but specify that the specific adjustment clauses should be written to include the provision described above.

This is particularly necessary because other Proposed Settlement provisions provide protections to the Company but not to ratepayers. Article 2.8 allows the Company to request a rate change in the event of an emergency or material changes in cost resulting from any type of law or order. However, it also specifies that except for these specific changes, rates shall remain unchanged until July 1, 2004. In other words, the Company has the ability to increase rates but ratepayers do not have symmetrical rights; if the

Company is overearning, even significantly, no party will have the right to examine the Company's cost of service and request a rate decrease.

Q. The Company has indicated that the rate reductions in the Proposed Settlement are a great benefit to customers. Might these rate reductions be a significant enough benefit to justify the low MGCs?

A. No. Since a MGC that is too low will prevent the development of a competitive market for generation service, it will frustrate the entire purpose of the retail electric competition effort. In addition, the benefits have been greatly exaggerated.

Q. Why are 1.5 percent rate reductions for five years not a large benefit?

A. First, the size of the reductions, even cumulatively, are small relative to what utilities in other regions have provided after restructuring. Second, since the Company may increase its rates under certain conditions, and will be allowed to defer some costs for later collection, it is not clear that these guaranteed reductions leave customers in a better position than normal ratemaking might produce.

Q. What size reductions have customers received in other states?

A. In three states, Massachusetts, California, and Rhode Island, all customers have received reductions of 10 percent or more, while Maryland, New Jersey, and Delaware have mandated cuts of 3 percent, 5 percent, and 7.5 percent, respectively. Illinois, Kentucky, New Hampshire and Texas also appear to be providing more significant rate reductions than the Proposed Settlement's 1.5 percent reductions.

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Q. How might customers be better off as a result of the normal ratemaking process?

A. The rate adjustment mechanisms could result in increases that eliminate all or part of these reductions. Thus the reductions of 1.5 percent, which will result in total revenue reductions of about $25 million per year, could be followed by increases of $30 to $50 million. Normal ratemaking practice might have produced larger decreases, or might not allow revenue increases for these incremental costs.

Q. Is there any specific indication in this case of the rate reduction that might occur under normal ratemaking?

A. Yes. The Company has been providing customers with small rate decreases over the last four years that reflect faster growth in revenue than in costs. When revenues increase faster than costs, we would expect the Company to be overearning. However, the Company has given up only 55 percent of the "excess"[4]. This suggests that a full rate investigation now might well determine that the Company was overearning and result in a rate decrease. The Company cites 1998 as evidence that the automatic increase would have been less than the 1.5 percent decrease. However, the Company's own Form 10-K for 1998 filed with the Securities and Exchange Commission notes that its 1998 revenues were lower than normal by $33 million because of milder than normal weather. If sales had been higher, variable costs would also have increased, but fixed costs would not have changed. If normal weather had occurred, the revenue/cost comparison would have resulted in larger total overearnings. It appears likely that a rate case based on a normalized 1998 cost of service would result in rates being lowered by considerably more than the 1.5 percent reduction in the Proposed Settlement. Also, normal ratemaking practice would not allow an increase for the incremental transition costs referenced in the adjustment clauses if the Company was overearning by that amount or more.

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4 The exception is property tax decreases, of which 100 percent has gone to ratepayers.

Q. Are there any other problems with the rate provisions of the settlement?

A. The proposed Direct Access rates show a Competitive Transition Charge (CTC) which is a demand rate for the General Service class. Since some customers on this rate do not have demand meters, it would appear that they would not pay any CTC. If this is a correct interpretation of the rate, an energy based CTC should be added to apply only to customers without demand readings.

Finally, based on my MGC calculations, it appears that the Special Contract customers would receive a market generation credit of 3.5 cents. This would appear to provide them much more of an opportunity to shop for power than other customers on the Extra-Large General Service class whose MGC is just above 3 cents. This does not seem an appropriate result. It could also be construed as prior discrimination.

Q. Does this complete your direct testimony?

A. Yes, it does.

- Represented the DOER at NEPOOL committees engaged in developing an Independent System Operator, a revised NEPOOL Agreement, and an Open Access Transmission Tariff for New England. Assisted the DOER in other matters including development of model for Boston Edison pilot program based on proxy for competitive market real-time pricing.

- Prepared alternative marginal cost study on Maine Public Service Company. Presented testimony advocating allocation of excess costs on the basis of generation allocators rather than EPMC.

- Prepared testimony on cost allocation and rate design for local gas distribution utility for Kansas Citizens' Utility Ratepayers Board. Assisted in settlement negotiations.

- Testified for Massachusetts Municipal Wholesale Electric Company on appropriate allocation of gas transition costs; assisted MMWEC in formulating response to generic docket on interruptible gas transportation; prepared comments.

EMPLOYMENT

Department of Public Utilities:
Director of Rates and Research,
1982 - 1984

EDUCATION

Ph.D., all but dissertation, Tufts University, Economics
B.A., Honors, Brown University,
International Relations and Economics
Study of Statistics, Boston College

HONORS

Bunting Institute Fellowship, 1970-71
Tufts University Economics Department Fellowship, 1967-68
Prize in International Relations, Brown University, 1965

LEE SMITH

LA CAPRA ASSOCIATES
Senior Economist

Ms. Lee Smith is a Senior Economist at La Capra Associates. Ms. Smith has over fifteen years experience in utility economics and regulation. Her work has encompassed all aspects of utility pricing, cost analysis, forecasting, and both demand-side and supply planning in electric, gas, and water utility cases. As a consultant, her clients have included gas and electric utilities, regulatory commissions and other public bodies. Ms. Smith has advised the Massachusetts Division of Energy Resources on position on changes in Integrated Resource Management, including proposal to open Transmission and Distribution access to meet resource needs. Previous to La Capra Associates, Ms. Smith was employed as the Director of Rates and Research at the Department of Public Utilities.

ACCOMPLISHMENTS

- Assisting the Arizona Corporation Commission in developing unbundled rates for all Arizona utilities; preparing positions, and negotiating with utilities.
- Advised and provided testimony on rate unbundling for the Maryland Office of the Public Counsel for all utilities in Maryland in restructuring proceedings.
- Advised Pennsylvania Office of the Public Advocate staff in restructuring proceedings; presented testimony on rate unbundling in eight cases.
- Assisted Massachusetts Division of Energy Resources in drafting restructuring legislation and negotiating additional restructuring settlements with utilities.
- Assisted Commission staff in both electricity restructuring cases and utility requests for Qualified Rate Orders allowing securitization of some stranded costs for the Pennsylvania Office of the Consumer Advocate.
- Assisted New Hampshire Public Utilities Commission staff in writing Draft Order on Restructuring; prepared discovery for utilities; prepared discovery questions for hearings on various issues, including corporate unbundling, market structure, transmission, stranded cost theory, measurement, and mitigation.
- Assisted DOER in all aspects of electric industry restructuring from rate unbundling to planning and developing revised market structure for the New England Power Pool.

Residential Service: Year 1 (1999)

New Direct Access Rate

May - October

	flat	per kWh
Basic Service Charge	10.00	
Original	7.50	
Incremental Cust. Chg.	2.50	0.00212
Distribution		0.04158
SBC		0.00115
CTC		0.00930
sum		0.05415

November - April

Basic Service Charge	10.00	
Original	7.50	
Incremental Cust. Chg.	2.50	0.00316
Distribution		0.03518
SBC		0.00115
CTC		0.00930
sum		0.04879

Old Unbundled Rate

May - October

	flat	per kWh		Weighted kWh
Basic Service Charge	7.50	0.08028	first 400 kWh	0.02498
		0.11191	next 400 kWh	0.02557
		0.13051	all additional kWh	0.06008
			sum	0.11063
Revenues	$27,514,672.50	$479,531,909.59	$ 507,046,582.09	
		$ 0.1106	average summer	

November - April

	flat	per kWh	
Basic Service Charge	7.50		
		0.08047	
Revenues	$ 27,547,912.50	$233,598,545.02	$261,146,457.52

Calculation of New Discounted Standard Offer Rate

May - October

Discounted Revenues			$ 499,440,883.36
Difference			$ 7,605,698.73
New Revenue Stream	$27,514,672.50	$471,926,210.86	$ 499,440,883.36
SO Discounted Rate*	7.50	0.10887	

Calculation of New Discounted Standard Offer Rate

November - April

Discounted Revenues			$257,229,260.66
Difference			$ 3,917,196.86
New Revenue Stream	$ 27,547,912.50	$229,681,348.16	$257,229,260.66
SO Discounted Rate*	7.50	0.07912	

Difference between Standard Offer and direct access rates

May - October

SO Rate		7.50	0.10887
direct access rate		7.50	0.05415
Difference		**0.00**	**0.054729016**
Annual Generation Credit	**TOTAL $**		**$237,226,866.17**
	per kWh		**0.055**
Weighted Average	**per kWh**		**0.0449**

November - April

SO Rate		7.50	0.07912
direct access rate		7.50	0.04879
		0.00	**0.030327371**
	TOTAL $		**$ 88,038,146.36**
	per kWh		**0.030**

* Assume reduction flows through energy charge.

Residential Service: Year 2 (2000)

New Direct Access Rate

May - October

	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00212
Distribution			0.04041
SBC			0.00115
CTC			0.00840
	sum		0.05208

November - April

Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00316
Distribution			0.03419
SBC			0.00115
CTC			0.00840
	sum		0.04690

Calculation of New Discounted Standard Offer Rate

May - October

Discounted Revenues			$ 491,949,270.11	
Difference			$ 15,097,311.98	$ 7,491,613.25
New Revenue Stream	$27,514,672.50	$464,434,597.61	$ 491,949,270.11	$464,434,597.61
SO Discounted Rate*	7.50	0.10715		

Calculation of New Discounted Standard Offer Rate

November - April

Discounted Revenues			$253,370,821.75
Difference			$ 7,775,635.77
New Revenue Stream	$ 27,547,912.50	$225,822,909.25	$253,370,821.75
SO Discounted Rate*	7.50	0.07779	

Difference between Standard Offer and direct access rates

May - October

SO Rate		7.50	0.10847
Direct Access		7.50000	0.05208
Difference		-	**0.05639**
Seasonal Generation Credit	**TOTAL $**		**$244,444,257.01**
	per kWh		**0.056**
Weighted Average	**per kWh**		**0.0462**

November - April

SO Rate		7.50	0.07779
Direct Access		7.50	0.04690
		-	**0.03089**
	TOTAL $		**$ 89,666,239.70**
	per kWh		**0.031**

* Assume reduction flows through energy charge.

Residential Service: Year 3 (2001)

New Direct Access Rate

May - October

	flat	per kWh
Basic Service Charge	10.00	
Original	7.50	
Incremental Cust. Chg.	2.50	0.00212
Distribution		0.03934
SBC		0.00115
CTC		0.00630
sum		0.04891

Calculation of New Discounted Standard Offer Rate

May - October

Discounted Revenues			$ 484,570,031.06	
Difference			$ 22,476,551.03	$ 7,379,239.05
New Revenue Stream	$27,514,672.50	$457,055,358.56	$ 484,570,031.06	$457,055,358.56
SO Discounted Rate*	7.50	0.10544		

Difference between Standard Offer and direct access rates

May - October

SO Rate		7.50	0.10544
Direct Access		7.50	0.04891
Difference		**0.00**	**0.05654**
Annual Generation Credit	**TOTAL $**		**$245,069,171.75**
	per kWh		**0.057**
Weighted Average	**per kWh**		**0.0469**

November - April

	flat	per kWh
Basic Service Charge	10.00	
Original	7.50	
Incremental Cust. Chg.	2.50	0.00316
Distribution		0.03329
SBC		0.00115
CTC		0.00630
sum		0.04390

Calculation of New Discounted Standard Offer Rate

November - April

Discounted Revenues			$249,570,259.43
Difference			$ 11,576,198.10
New Revenue Stream	$ 27,547,912.50	$222,022,346.93	$249,570,259.43
SO Discounted Rate*	7.50	0.07648	

November - April

SO Rate		7.50	0.07648
Direct Access		7.50	0.04390
		-	**0.03258**
	TOTAL $		**$ 94,574,458.72**
	per kWh		**0.033**

* Assume reduction flows through energy charge.

Residential Service: Year 4 (2002)

New Direct Access Rate

May - October	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00212
Distribution			0.03837
SBC			0.00115
CTC			0.00560
	sum		0.04724

November - April	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00316
Distribution			0.03247
SBC			0.00115
CTC			0.00560
	sum		0.04238

Calculation of New Discounted Standard Offer Rate

May - October				
Discounted Revenues			$ 477,301,480.60	
Difference			$ 29,745,101.50	$ 7,268,550.47
New Revenue Stream	$27,514,672.50	$449,786,808.10	$ 477,301,480.60	$449,786,808.10
SO Discounted Rate*	7.50	0.10377		

November - April			
Discounted Revenues			$245,826,705.53
Difference			$ 15,319,751.99
New Revenue Stream	$ 27,547,912.50	$218,278,793.03	$245,826,705.53
SO Discounted Rate*	7.50	0.07519	

Difference between Standard Offer and direct access rates

May - October			
SO Rate		7.50	0.10377
Direct Access		7.50	0.04724
Difference		**0.00**	**0.056531383**
Annual Generation Credit	**TOTAL $**		**$245,039,356.72**
	per kWh		**0.057**
Weighted Average	**per kWh**		**0.0470**

November - April			
SO Rate		7.50	0.07519
Direct Access		7.50	0.04238
		0.00	**0.03280942**
	TOTAL $		**$ 95,243,354.04**
	per kWh		**0.033**

* Assume reduction flows through energy charge.

Residential Service: *Year 5* (2003)

New Direct Access Rate

May - October

	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00212
Distribution			0.03748
SBC			0.00115
CTC			0.00500
	sum		0.04575

November - April

	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00316
Distribution			0.03172
SBC			0.00115
CTC			0.00500
	sum		0.04103

Calculation of New Discounted Standard Offer Rate

May - October

Discounted Revenues			$ 470,141,958.39	
Difference			$ 36,904,623.71	$ 7,159,522.21
New Revenue Stream	$27,514,672.50	$442,627,285.89	$ 470,141,958.39	$442,627,285.89
SO Discounted Rate*	7.50	0.10212		

Calculation of New Discounted Standard Offer Rate

November - April

Discounted Revenues			$242,139,304.95
Difference			$ 19,007,152.57
New Revenue Stream	$ 27,547,912.50	$214,591,392.45	$242,139,304.95
SO Discounted Rate*	7.50	0.07392	

Difference between Standard Offer and direct access rates

May - October

SO Rate		7.50	0.10212
Direct Access rate		7.50	0.04575
Difference		**0.00**	**0.056369658**
Annual Generation Credit	**TOTAL $**		**$244,338,346.97**
	per kWh		**0.056**
Weighted Average	**per kWh**		**0.0470**

November - April

SO Rate		7.50	0.07392
Direct Access rate		7.50	0.04103
		0.00	**0.032889184**
	TOTAL $		**$ 95,474,905.07**
	per kWh		**0.033**

* Assume reduction flows through energy charge.

Residential Service: Year 6 (2004)

New Direct Access Rate

May - October	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00212
Distribution			0.03689
SBC			0.00115
CTC			0.00360
	sum		0.04376

November - April	flat		per kWh
Basic Service Charge		10.00	
Original		7.50	
Incremental Cust. Chg.		2.50	0.00316
Distribution			0.03122
SBC			0.00115
CTC			0.00360
	sum		0.03913

Calculation of Discounted Standard Offer Rate

May - October			
Revenues (no further discount from 2003)			$ 470,141,958.39
Difference			$ 36,904,623.71
New Revenue Stream	$27,514,672.50	$442,627,285.89	$ 470,141,958.39
SO Discounted Rate*	7.50	0.10212	

Calculation of Discounted Standard Offer Rate

November - April			
Revenues (no further discount from 2003)			$242,139,304.95
Difference			$ 19,007,152.57
New Revenue Stream	$ 27,547,912.50	$214,591,392.45	$242,139,304.95
SO Discounted Rate*	7.50	0.07392	

Difference between Standard Offer and direct access rates

May - October			
SO Rate		7.50	0.10212
Direct Access rate		7.50	0.04376
Difference		**0.00**	**0.058359658**
Annual Generation Credit	**TOTAL $**		**$252,964,145.48**
	per kWh		**0.058**
Weighted Average	**per kWh**		**0.0489**

November - April			
SO Rate		7.50	0.07392
Direct Access rate		7.50	0.03913
		0.00	**0.034789184**
	TOTAL $		**$100,990,466.59**
	per kWh		**0.035**

* Assume reduction flows through energy charge.

General Service: Year 1 (1999)
SUMMER

New Direct Access Rate

June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.04255			0.00115	$ 2.43	
	revenue	$ 10,388		$ 24,549			$ 663	$ -	$ 35,600
Formula 2	rate	12.50		0.04255	0.02901		0.00115	$ 2.43	
	revenue	$ 775		$ 6,532	$ 3,190		$ 303	$ -	$ 10,800
Formula 3	rate	12.50	0.721	0.04255			0.00115	$ 2.43	
	revenue	$ 263,975	$ 385,960	$ 2,805,947			$ 75,836	$ 535,314	$ 4,067,032
Formula 4	rate	12.50	0.721	0.04255	0.02901		0.00115	$ 2.43	
	revenue	$ 899,550	$ 2,322,307	$ 21,287,803	$ 18,876,888		$ 1,323,654	$ 7,826,916	$ 52,537,118
Formula 5	rate	12.50	0.721	0.04255	0.02901	0.01811	0.00115	$ 2.43	
	revenue	$ 126,050	$ 2,782,311	$ 17,482,383	$ 12,169,956	$ 17,193,200	$ 2,046,715	$ 9,377,275	$ 61,177,890
total revenues		$ 1,300,738	$ 5,490,578	$ 41,607,214	$ 31,050,034	$ 17,193,200	$ 3,447,172	$ 17,739,505	$ 117,828,441

Original Unbundled Rate

June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.11018					$ 73,956
	revenue	$ 10,388		$ 63,568					
Formula 2	rate	12.50		0.11018	0.07550				
	revenue	$ 775		$ 16,915	$ 8,302				$ 25,992
Formula 3	rate	12.50	1.85	0.11018					
	revenue	$ 263,975	$ 990,327	$ 7,265,786					$ 8,520,088
Formula 4	rate	12.50	1.85	0.11018	0.07550				
	revenue	$ 899,550	$ 5,958,763	$ 55,123,152	$ 49,128,060				$ 111,109,525
Formula 5	rate	12.50	1.85	0.11018	0.07550	0.04756			
	revenue	$ 126,050	$ 7,139,078	$ 45,269,307	$ 31,672,929	$ 45,152,324			$ 129,359,688
total revenues		$ 1,300,738	$ 14,088,168	$ 107,738,728	$ 80,809,291	$ 45,152,324			$ 249,089,249

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues		
						Discounted Revenues	$ 245,352,910		
						Difference	$ 3,736,339		
Standard Offer revenue	$ 1,300,738	$ 13,875,736	$ 106,114,164	$ 79,590,789	$ 44,471,484		$ 245,352,910	$ 245,352,910	
SO Discounted Rates	$ 12.50	$ 1.82	$ 0.10852	$ 0.07436	$ 0.04684	Original Rate less Cust charges	247,788,511	$ 0.0819	Ave. revenue
						Percent Reduction from KW and kWh	1.508%		
						Total Reduction to Full Rate	1.500%		

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.82	$ 0.10852	$ 0.07436	$ 0.04684	0.00000	0.00000	
direct access rate	$ 12.50	$ 0.72	$ 0.04255	$ 0.02901	$ 0.01811	0.00115	$ 2.43	
Difference	$ -	**1.10**	**0.06597**	**0.04535**	**0.02873**	**(0.00115)**	**(2.43000)**	**TOTAL $**
Annual Generation Credit		**$ 8,385,158**	**$ 64,506,949**	**$ 48,540,755**	**$ 27,278,284**	**$ (3,447,172)**	**$ (17,739,505)**	**$ 127,524,470**
							per kWh	**$ 0.0425**

WINTER (1999)

New Direct Access Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03827			0.00115	2.43	
	revenue	$ 18,763		$ 39,329			$ 1,182	$ -	$ 59,273
Formula 2	rate	12.50		0.03827	0.02600		0.00115	2.43	
	revenue	$ 1,313		$ 9,909	$ 5,115		$ 524.02	$ -	$ 16,861
Formula 3	rate	12.50	0.652	0.03827			0.00115	2.43	
	revenue	$ 573,300	$ 638,700	$ 5,056,351			$ 151,942	$ 1,300,808	$ 7,721,100
Formula 4	rate	12.50	0.652	0.03827	0.02600		0.00115	2.43	
	revenue	$ 1,080,200	$ 2,557,360	$ 23,143,821	$ 17,944,535		$ 1,489,164	$ 7,826,916	$ 54,041,996
Formula 5	rate	12.50	0.652	0.03827	0.02600	0.01614	0.00115	2.43	
	revenue	$ 124,850	$ 2,588,136	$ 16,131,447	$ 10,729,270	$ 14,964,970	$ 2,025,585	$ 9,377,275	$ 55,941,533
total revenues		$ 1,798,425	$ 5,784,196	$ 44,380,857	$ 28,678,920	$ 14,964,970	$ 3,668,397	$ 18,504,999	$ 117,780,764

Original Unbundled Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	total revenues
Formula 1	rate	12.50		0.09925			
	revenue	$ 18,762.50		$ 101,995			$ 120,758
Formula 2	rate	12.50		0.09925	0.06780		
	revenue	$ 1,313		$ 25,699	$ 13,339		$ 40,350
Formula 3	rate	12.50	1.67	0.09925			
	revenue	$ 573,300	$ 1,635,934	$ 13,113,217			$ 15,322,451
Formula 4	rate	12.50	1.67	0.09925	0.06780		
	revenue	$ 1,080,200	$ 6,550,294	$ 60,021,537	$ 46,793,825		$ 114,445,857
Formula 5	rate	12.50	1.67	0.09925	0.06780	0.04252	
	revenue	$ 124,850	$ 6,629,122	$ 41,835,540	$ 27,978,634	$ 39,424,443	$ 115,992,589
total revenues		$ 1,798,425	$ 14,815,350	$ 115,097,988	$ 74,785,798	$ 39,424,443	$ 245,922,005

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 242,233,175
Difference							$ 3,688,830
New Revenue Stream	$ 1,798,425	$ 14,591,483	$ 113,358,800	$ 73,655,747	$ 38,828,720		$ 242,233,175
SO Discounted Rates	$ 12.50	$ 1.64	$ 0.09775	$ 0.06678	$ 0.04188	Original Rate less Cust charges	$ 244,123,580
						Percent Reduction from KW and kWh	1.511%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.64	$ 0.09775	$ 0.06678	$ 0.04188	0.00000	0.00	
direct access rate	$ 12.50	$ 0.65	$ 0.03827	$ 0.02600	$ 0.01614	0.00115	2.43	
Difference	$ -	**0.99**	**0.05948**	**0.04078**	**0.02574**	$ **(0.00115)**	$ **(2.43000)**	**TOTAL $**
Annual Generation Credit		$ **8,807,286.02**	$ **68,977,943.26**	$ **44,976,827.36**	$ **23,863,750.44**	$ **(3,668,397)**	$ **(18,504,999)**	$ **124,452,410.87**
								per kWh
								$ **0.0390**

Weighted average per kWh **0.04072**

General Service: Year 2 (2000)
SUMMER
New Direct Access Rate
June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.04075			0.00115	$ 2.20	
	revenue	$ 10,388		$ 23,511			$ 576,951	$ -	$ 610,849
Formula 2	rate	12.50		0.04075	0.02779		0.00115	$ 2.20	
	revenue	$ 775		$ 6,256	$ 3,056		$ 303	$ -	$ 10,390
Formula 3	rate	12.50	0.691	0.04075			0.00115	$ 2.20	
	revenue	$ 263,975	$ 369,901	$ 2,687,246			$ 75,836	$ 1,177,686	$ 4,574,645
Formula 4	rate	12.50	0.691	0.04075	0.02779		0.00115	$ 2.20	
	revenue	$ 899,550	$ 2,225,679	$ 20,387,261	$ 18,083,030		$ 1,323,654	$ 7,086,097	$ 50,005,271
Formula 5	rate	12.50	0.691	0.04075	0.02779	0.01735	0.00115	$ 2.20	
	revenue	$ 126,050	$ 2,666,542	$ 16,742,823	$ 11,658,155	$ 16,471,674	$ 2,046,715	$ 8,489,714	$ 58,201,673
total revenues		$ 1,300,738	$ 5,262,121	$ 39,847,097	$ 29,744,241	$ 16,471,674	$ 4,023,459	$ 16,753,497	$ 113,402,828

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 241,672,616
Difference							$ 3,680,294
New Revenue Stream	$ 1,300,738	$ 13,666,491	$ 104,513,968	$ 78,390,564	$ 43,800,857		$ 241,672,616
SO Discounted Rates	$ 12.50	$ 1.79	$ 0.10688	$ 0.07324	$ 0.04614	Original Rate less Cust charges	244,052,173
						Percent Reduction from KW and kWh	1.508%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.79	$ 0.10688	$ 0.07324	$ 0.04614	0.00000	0.00000	
direct access rate	$ 12.50	$ 0.691	$ 0.04075	$ 0.02779	$ 0.01735	0.00115	2.20	
Difference	**$ -**	**1.10**	**0.06613**	**0.04545**	**0.02879**	**(0.00115)**	**(2.20000)**	**TOTAL $**
Annual Generation Credit		**$ 8,404,369.74162**	**$ 64,666,871**	**$ 48,646,323**	**$ 27,329,182**	**$ (4,023,459)**	**$ (16,753,497)**	**$ 128,269,789**
								per kWh
								$ 0.0428

WINTER (2000)

New Direct Access Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03666			0.00115	2.20	
	revenue	$ 18,763		$ 37,674			$ 1,182	$ -	$ 57,618
Formula 2	rate	12.50		0.03666	0.02490		0.00115	2.20	
	revenue	$ 1,313		$ 9,492	$ 4,899		$ 524.02	$ -	$ 16,228
Formula 3	rate	12.50	0.624	0.03666			0.00115	2.20	
	revenue	$ 573,300	$ 611,271	$ 4,843,633			$ 151,942	$ 2,155,122	$ 8,335,267
Formula 4	rate	12.50	0.624	0.03666	0.02490		0.00115	2.20	
	revenue	$ 1,080,200	$ 2,447,535	$ 22,170,172	$ 17,185,343		$ 1,489,164	$ 8,629,130	$ 53,001,545
Formula 5	rate	12.50	0.624	0.03666	0.02490	0.01546	0.00115	2.20	
	revenue	$ 124,850	$ 2,476,989	$ 15,452,805	$ 10,275,339	$ 14,334,475	$ 2,025,585	$ 8,732,975	$ 53,423,019
total revenues		$ 1,798,425	$ 5,535,795	$ 42,513,776	$ 27,465,581	$ 14,334,475	$ 3,668,397	$ 19,517,227	$ 114,833,677

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 238,599,677
Difference							$ 3,633,498
New Revenue Stream	$ 1,798,425	$ 14,370,973	$ 111,645,699	$ 72,542,647	$ 38,241,933		$ 238,599,677
SO Discounted Rates	$ 12.50	$ 1.62	$ 0.09627	$ 0.06577	$ 0.04124	Original Rate less Cust charges	$ 240,434,750
						Percent Reduction from KW and kWh	1.511%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.62	$ 0.09627	$ 0.06577	$ 0.04124	0.00000	0.00	
direct access rate	$ 12.50	$ 0.624	$ 0.03666	$ 0.02490	$ 0.01546	0.00115	2.20	
Difference	$ -	1.00	0.05961	0.04087	0.02578	$ (0.00115)	$ (2.20000)	TOTAL $
Annual Generation Credit		$ 8,835,177.72	$ 69,131,923.32	$ 45,077,066.01	$ 23,907,457.51	$ (3,668,397)	$ (19,517,227)	$ 123,766,000.12
								per kWh
								$ 0.0388

Weighted average per kWh 0.04073

General Service: Year 3 (2001)

SUMMER

New Direct Access Rate

June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03912			0.00115	$ 1.66	
	revenue	$ 10,388		$ 22,570			$ 663	$ -	$ 33,621
Formula 2	rate	12.50		0.03912	0.02667		0.00115	$ 1.66	
	revenue	$ 775		$ 6,006	$ 2,933		$ 303	$ -	$ 10,016
Formula 3	rate	12.50	0.663	0.03912			0.00115	$ 1.66	
	revenue	$ 263,975	$ 354,912	$ 2,579,756			$ 75,836	$ 888,618	$ 4,163,097
Formula 4	rate	12.50	0.663	0.03912	0.02667		0.00115	$ 1.66	
	revenue	$ 899,550	$ 2,135,492	$ 19,571,771	$ 17,354,243		$ 1,323,654	$ 5,346,782	$ 46,631,492
Formula 5	rate	12.50	0.663	0.03912	0.02667	0.01665	0.00115	$ 1.66	
	revenue	$ 126,050	$ 2,558,491	$ 16,073,110	$ 11,188,305	$ 15,807,111	$ 2,046,715	$ 6,405,875	$ 54,205,657
total revenues		$ 1,300,738	$ 5,048,895	$ 38,253,213	$ 28,545,481	$ 15,807,111	$ 3,447,172	$ 12,641,275	$ 105,043,884

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 238,047,527
Difference							$ 3,625,089
New Revenue Stream	$ 1,300,738	$ 13,460,384	$ 102,937,775	$ 77,208,342	$ 43,140,288		$ 238,047,527
SO Discounted Rates	$ 12.50	$ 1.77	$ 0.10527	$ 0.07214	$ 0.04544	Original Rate less Cust charges	240,371,879
						Percent Reduction from KW and kWh	1.508%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.77	$ 0.10527	$ 0.07214	$ 0.04544	0.00000	0.00	
direct access rate	$ 12.50	$ 0.663	$ 0.03912	$ 0.02667	$ 0.01665	0.00115	$ 1.66	
Difference	$ -	**1.10**	**0.06615**	**0.04547**	**0.02879**	**(0.00115)**	**(1.66000)**	**TOTAL $**
Annual Generation Credit		**$ 8,411,489.39256**	**$ 64,684,562**	**$ 48,662,862**	**$ 27,333,177**	**$ (3,447,172)**	**$ (12,641,275)**	**$ 133,003,643**
								per kWh
								$ 0.0444

WINTER (2001)

<u>New Direct Access Rate</u>

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03519			0.00115	1.66	
	revenue	$ 18,763		$ 36,163			$ 1,182	$ -	$ 56,108
Formula 2	rate	12.50		0.03519	0.02390		0.00115	1.66	
	revenue	$ 1,313		$ 9,112	$ 4,702		$ 524.02	$ -	$ 15,650
Formula 3	rate	12.50	0.599	0.03519			0.00115	1.66	
	revenue	$ 573,300	$ 586,781	$ 4,649,412			$ 151,942	$ 1,626,138	$ 7,587,572
Formula 4	rate	12.50	0.599	0.03519	0.02390		0.00115	1.66	
	revenue	$ 1,080,200	$ 2,349,477	$ 21,281,188	$ 16,495,169		$ 1,489,164	$ 6,511,071	$ 49,206,269
Formula 5	rate	12.50	0.599	0.03519	0.02390	0.01484	0.00115	1.66	
	revenue	$ 124,850	$ 2,377,751	$ 14,833,175	$ 9,862,675	$ 13,759,613	$ 3,668,397	$ 6,589,426	$ 51,215,887
total revenues		$ 1,798,425	$ 5,314,009	$ 40,809,050	$ 26,362,545	$ 13,759,613	$ 5,311,209	$ 14,726,635	$ 108,081,486

<u>Calculation of New Discounted Standard Offer Rate (discount at 1.5%)</u>

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 235,020,682
Difference							$ 3,578,995
New Revenue Stream	$ 1,798,425	$ 14,153,771	$ 109,958,295	$ 71,446,243	$ 37,663,947		$ 235,020,682
SO Discounted Rates	$ 12.50	$ 1.60	$ 0.09482	$ 0.06477	$ 0.04062	Original Rate less Cust charges	$ 236,801,252
						Percent Reduction from KW and kWh	1.511%
						Total Reduction to Full Rate	1.500%

<u>Difference between Standard Offer and direct access rates</u>

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.60	$ 0.09482	$ 0.06477	$ 0.04062	0.00000	0.00	
direct access rate	$ 12.50	$ 0.599	$ 0.03519	$ 0.02390	$ 0.01484	0.00115	1.66	
Difference	**$ -**	**1.00**	**0.05963**	**0.04087**	**0.02578**	**$ (0.00115)**	**$ (1.66000)**	**TOTAL $**
Annual Generation Credit		**$ 8,839,762.65**	**$ 69,149,245.03**	**$ 45,083,697.63**	**$ 23,904,334.54**	**$ (5,311,209)**	**$ (14,726,635)**	**$ 126,939,195.98**
								per kWh
								$ 0.0398

Weighted average per kWh **0.04201**

General Service: Year 4 (2002)
SUMMER
New Direct Access Rate
June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03763			0.00115	$ 1.46	
	revenue	$ 10,388		$ 21,711			$ 663	$ -	$ 32,762
Formula 2	rate	12.50		0.03763	0.02565		0.00115	$ 1.46	
	revenue	$ 775		$ 5,777	$ 2,820		$ 303	$ -	$ 9,675
Formula 3	rate	12.50	0.638	0.03763			0.00115	$ 1.46	
	revenue	$ 263,975	$ 341,529	$ 2,481,499			$ 75,836	$ 781,556	$ 3,944,395
Formula 4	rate	12.50	0.638	0.03763	0.02565		0.00115	$ 1.46	
	revenue	$ 899,550	$ 2,054,968	$ 18,826,322	$ 16,690,526		$ 1,323,654	$ 4,702,591	$ 44,497,612
Formula 5	rate	12.50	0.638	0.03763	0.02565	0.01602	0.00115	$ 1.46	
	revenue	$ 126,050	$ 2,462,017	$ 15,460,919	$ 10,760,406	$ 15,209,004	$ 2,046,715	$ 5,634,083	$ 51,699,193
total revenues		$ 1,300,738	$ 4,858,514	$ 36,796,227	$ 27,453,752	$ 15,209,004	$ 3,447,172	$ 11,118,230	$ 100,183,637

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 234,476,814
Difference							$ 3,570,713
New Revenue Stream	$ 1,300,738	$ 13,257,369	$ 101,385,225	$ 76,043,854	$ 42,489,629		$ 234,476,814
SO Discounted Rates	$ 12.50	$ 1.74	$ 0.10368	$ 0.07105	$ 0.04476	Original Rate less Cust charges	236,746,790
						Percent Reduction from KW and kWh	1.508%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.74	$ 0.10368	$ 0.07105	$ 0.04476	0.00000	0.00	
direct access rate	$ 12.50	$ 0.638	$ 0.03763	$ 0.02565	$ 0.01602	0.00115	$ 1.46	
Difference	**$ -**	**1.10**	**0.06605**	**0.04540**	**0.02874**	**(0.00115)**	**(1.46000)**	**TOTAL $**
Annual Generation Credit		**$ 8,398,854.96565**	**$ 64,588,997**	**$ 48,590,102**	**$ 27,280,625**	**$ (3,447,172)**	**$ (11,118,230)**	**$ 134,293,177**
								per kWh
								$ 0.0448

WINTER (2002)
New Direct Access Rate
November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03385			0.00115	1.46	
	revenue	$ 18,763		$ 34,786			$ 1,182	$ -	$ 54,731
Formula 2	rate	12.50		0.03385	0.02299		0.00115	1.46	
	revenue	$ 1,313		$ 8,765	$ 4,523		$ 524.02	$ -	$ 15,124
Formula 3	rate	12.50	0.576	0.03385			0.00115	1.46	
	revenue	$ 573,300	$ 564,250	$ 4,472,367			$ 151,942	$ 1,430,217	$ 7,192,076
Formula 4	rate	12.50	0.576	0.03385	0.02299		0.00115	1.46	
	revenue	$ 1,080,200	$ 2,259,263	$ 20,470,821	$ 15,867,110		$ 1,489,164	$ 5,726,605	$ 46,893,163
Formula 5	rate	12.50	0.576	0.03385	0.02299	0.01427	0.00115	1.46	
	revenue	$ 124,850	$ 2,286,452	$ 14,268,343	$ 9,487,150	$ 13,231,110	$ 2,025,585	$ 5,795,520	$ 47,219,010
total revenues		$ 1,798,425	$ 5,109,965	$ 39,255,082	$ 25,358,783	$ 13,231,110	$ 3,668,397	$ 12,952,342	$ 101,374,104

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 231,495,372
Difference							$ 3,525,310
New Revenue Stream	$ 1,798,425	$ 13,939,828	$ 108,296,202	$ 70,366,285	$ 37,094,632		$ 231,495,372
SO Discounted Rates	$ 12.50	$ 1.57	$ 0.09338	$ 0.06379	$ 0.04001	Original Rate less Cust charges	$ 233,222,257
						Percent Reduction from KW and kWh	1.512%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy			
SO Rate	$ 12.50	$ 1.57	$ 0.09338	$ 0.06379	$ 0.04001	0.00000	0.00	
direct access rate	$ 12.50	$ 0.576	$ 0.03385	$ 0.02299	$ 0.01427	0.00115	1.46	
Difference	**$ -**	**1.00**	**0.05953**	**0.04080**	**0.02574**	**$ (0.00115)**	**$ (1.46000)**	**TOTAL $**
Annual Generation Credit		**$ 8,829,862.69**	**$ 69,041,119.74**	**$ 45,007,502.12**	**$ 23,863,521.46**	**$ (3,668,397)**	**$ (12,952,342)**	**$ 130,121,267.15**
								per kWh
								$ 0.0408

Weighted average per kWh **0.04273**

General Service: Year 5 (2003)
SUMMER
New Direct Access Rate
June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03627			0.00115	$ 1.30	
	revenue	$ 10,388		$ 20,926			$ 663	$ -	$ 31,977
Formula 2	rate	12.50		0.03627	0.02473		0.00115	$ 1.30	
	revenue	$ 775		$ 5,568	$ 2,719		$ 303	$ -	$ 9,365
Formula 3	rate	12.50	0.615	0.03627			0.00115	$ 1.30	
	revenue	$ 263,975	$ 329,217	$ 2,391,814			$ 75,836	$ 695,906	$ 3,756,748
Formula 4	rate	12.50	0.615	0.03627	0.02473		0.00115	$ 1.30	
	revenue	$ 899,550	$ 1,980,886	$ 18,145,913	$ 16,091,880		$ 1,323,654	$ 4,187,239	$ 42,629,122
Formula 5	rate	12.50	0.615	0.03627	0.02473	0.01544	0.00115	$ 1.30	
	revenue	$ 126,050	$ 2,373,261	$ 14,902,140	$ 10,374,457	$ 14,658,366	$ 2,046,715	$ 5,016,649	$ 49,497,638
total revenues		$ 1,300,738	$ 4,683,364	$ 35,466,361	$ 26,469,056	$ 14,658,366	$ 3,447,172	$ 9,899,794	$ 95,924,851

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 230,959,662
Difference							$ 3,517,152
New Revenue Stream	$ 1,300,738	$ 13,057,399	$ 99,855,963	$ 74,896,833	$ 41,848,729		$ 230,959,662
SO Discounted Rates	$ 12.50	$ 1.71	$ 0.10212	$ 0.06998	$ 0.04408	Original Rate less Cust charges	233,176,077
						Percent Reduction from KW and kWh	1.508%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.71	$ 0.10212	$ 0.06998	$ 0.04408	0.00000	0.00	
direct access rate	$ 12.50	$ 0.615	$ 0.03627	$ 0.02473	$ 0.01544	0.00115	$ 1.30	
Difference	$ -	**1.10**	**0.06585**	**0.04525**	**0.02864**	**(0.00115)**	**(1.30000)**	**TOTAL $**
Annual Generation Credit		**$ 8,374,035.31290**	**$ 64,389,602**	**$ 48,427,777**	**$ 27,190,363**	**$ (3,447,172)**	**$ (9,899,794)**	**$ 135,034,811**
								per kWh
								$ 0.0450

WINTER (2003)
New Direct Access Rate
November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03263			0.00115	1.30	
	revenue	$ 18,763		$ 33,533			$ 1,182	$ -	$ 53,477
Formula 2	rate	12.50		0.03263	0.02216		0.00115	1.30	
	revenue	$ 1,313		$ 8,449	$ 4,360		$ 524.02	$ -	$ 14,645
Formula 3	rate	12.50	0.555	0.03263			0.00115	1.30	
	revenue	$ 573,300	$ 543,679	$ 4,311,177			$ 151,942	$ 1,273,481	$ 6,853,578
Formula 4	rate	12.50	0.555	0.03263	0.02216		0.00115	1.30	
	revenue	$ 1,080,200	$ 2,176,894	$ 19,733,025	$ 15,294,265		$ 1,489,164	$ 5,099,032	$ 44,872,580
Formula 5	rate	12.50	0.555	0.03263	0.02216	0.01376	0.00115	1.30	
	revenue	$ 124,850	$ 2,203,091	$ 13,754,092	$ 9,144,639	$ 12,758,239	$ 2,025,585	$ 5,160,394	$ 45,170,892
total revenues		$ 1,798,425	$ 4,923,664	$ 37,840,276	$ 24,443,264	$ 12,758,239	$ 3,668,397	$ 11,532,907	$ 96,965,172

Calculation of New Discounted Standard Offer Rate (discount at 1.5%)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 228,022,941
Difference							$ 3,472,431
New Revenue Stream	$ 1,798,425	$ 13,729,093	$ 106,659,040	$ 69,302,527	$ 36,533,856		$ 228,022,941
SO Discounted Rates	$ 12.50	$ 1.55	$ 0.09197	$ 0.06283	$ 0.03940	Original Rate less Cust charges	$ 229,696,947
						Percent Reduction from KW and kWh	1.512%
						Total Reduction to Full Rate	1.500%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.55	$ 0.09197	$ 0.06283	$ 0.03940	0.00	0.00	
direct access rate	$ 12.50	$ 0.555	$ 0.03263	$ 0.02216	$ 0.01376	0.00115	1.30	
Difference	$ -	**0.99**	**0.05934**	**0.04067**	**0.02564**	**$ (0.00115)**	**$ (1.30000)**	**TOTAL $**
Annual Generation Credit		**$ 8,805,428.94**	**$ 68,818,764.55**	**$ 44,859,263.14**	**$ 23,775,616.26**	**$ (3,668,397)**	**$ (11,532,907)**	**$ 131,057,768.76**
								per kWh
								$ 0.0411

Weighted average per kWh **0.04301**

General Service: Year 6 (2004)
SUMMER
New Direct Access Rate
June - October

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03537			0.00115	$ 0.94	
	revenue	$ 10,388		$ 20,407			$ 663	$ -	$ 31,458
Formula 2	rate	12.50		0.03537	0.02411		0.00115	$ 0.94	
	revenue	$ 775		$ 5,430	$ 2,651		$ 303	$ -	$ 9,159
Formula 3	rate	12.50	0.600	0.03537			0.00115	$ 0.94	
	revenue	$ 263,975	$ 321,187	$ 2,332,464			$ 75,836	$ 503,193	$ 3,496,656
Formula 4	rate	12.50	0.600	0.03537	0.02411		0.00115	$ 0.94	
	revenue	$ 899,550	$ 1,932,572	$ 17,695,642	$ 15,688,444		$ 1,323,654	$ 3,027,696	$ 40,567,558
Formula 5	rate	12.50	0.600	0.03537	0.02411	0.01506	0.00115	$ 0.94	
	revenue	$ 126,050	$ 2,315,377	$ 14,532,360	$ 10,114,362	$ 14,297,603	$ 2,046,715	$ 3,627,423	$ 47,059,889
total revenues		$ 1,300,738	$ 4,569,136	$ 34,586,302	$ 25,805,457	$ 14,297,603	$ 3,447,172	$ 7,158,312	$ 91,164,720

Calculation of Standard Offer Rate (no further discount from 2003)

	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 230,959,662
Difference							$ -
New Revenue Stream	$ 1,300,738	$ 13,057,399	$ 99,855,963	$ 74,896,833	$ 41,848,729		$ 230,959,662
SO Rates	$ 12.50	$ 1.71	$ 0.10212	$ 0.06998	$ 0.04408	Original Rate less Cust charges	229,658,925
						Percent Reduction from KW and kWh	0.000%
						Total Reduction to Full Rate	0.000%

Difference between Standard Offer and direct access rates

June - October	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.71	$ 0.10212	$ 0.06998	$ 0.04408	0.00000	0.00	
direct access rate	$ 12.50	$ 0.600	$ 0.03537	$ 0.02411	$ 0.01506	0.00115	$ 0.94	
Difference	**$ -**	**1.11**	**0.06675**	**0.04587**	**0.02902**	**(0.00115)**	**(0.94000)**	**TOTAL $**
Annual Generation Credit		**$ 8,488,263.70290**	**$ 65,269,660**	**$ 49,091,376**	**$ 27,551,126**	**$ (3,447,172)**	**$ (7,158,312)**	**$ 139,794,942**
								per kWh
								$ 0.0466

WINTER (2004)

New Direct Access Rate

November - May

		flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	total revenues
Formula 1	rate	12.50		0.03182			0.00115	0.94	
	revenue	$ 18,763		$ 32,700			$ 1,182	$ -	$ 52,644
Formula 2	rate	12.50		0.03182	0.02161		0.00115	0.94	
	revenue	$ 1,313		$ 8,239	$ 4,251		$ 524.02	$ -	$ 14,327
Formula 3	rate	12.50	0.541	0.03182			0.00115	0.94	
	revenue	$ 573,300	$ 529,964	$ 4,204,157			$ 151,942	$ 920,825	$ 6,380,187
Formula 4	rate	12.50	0.541	0.03182	0.02161		0.00115	0.94	
	revenue	$ 1,080,200	$ 2,121,982	$ 19,243,177	$ 14,914,669		$ 1,489,164	$ 3,686,992	$ 42,536,184
Formula 5	rate	12.50	0.541	0.03182	0.02161	0.01342	0.00115	0.94	
	revenue	$ 124,850	$ 2,147,518	$ 13,412,664	$ 8,917,674	$ 12,442,992	$ 2,025,585	$ 3,731,362	$ 42,802,645
total revenues		$ 1,798,425	$ 4,799,464	$ 36,900,937	$ 23,836,594	$ 12,442,992	$ 3,668,397	$ 8,339,179	$ 91,785,988

Calculation of Standard Offer Rate (no further discount from 2003)

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy		total revenues
Discounted Revenues							$ 228,022,941
Difference							$ -
New Revenue Stream	$ 1,798,425	$ 13,729,093	$ 106,659,040	$ 69,302,527	$ 36,533,856		$ 228,022,941
SO Rates	$ 12.50	$ 1.55	$ 0.09197	$ 0.06283	$ 0.03940	Original Rate less Cust charges	$ 226,224,516
						Percent Reduction from KW and kWh	0.000%
						Total Reduction to Full Rate	0.000%

Difference between Standard Offer and direct access rates

November - May	flat	Demand	block 1 energy	block 2 energy	block 3 energy	SBC	CTC/kW	
SO Rate	$ 12.50	$ 1.55	$ 0.09197	$ 0.06283	$ 0.03940	0.00000	0.00	
direct access rate	$ 12.50	$ 0.541	$ 0.03182	$ 0.02161	$ 0.01342	0.00115	0.94	
Difference	**$ -**	**1.01**	**0.06015**	**0.04122**	**0.02598**	**$ (0.00115)**	**$ (0.94000)**	**TOTAL $**
Annual Generation Credit		**$ 8,929,629.48**	**$ 69,758,103.30**	**$ 45,465,932.60**	**$ 24,090,863.46**	**$ (3,668,397)**	**$ (8,339,179)**	**$ 136,236,952.81**
								per kWh
								$ 0.0427

Weighted average per kWh **0.04461**

APS PROPOSED SETTLEMENT

Calculation of implicit generation credits and Regulatory Asset Savings

Extra Large General Service: Year 1 (1999)

New Direct Access Delivery Rates

	flat	per kW	per kWh	Total revenue
Basic Delivery Service	2430.00			
Distribution		3.53	0.00999	
SBC			0.00115	
CTC		2.82		
Sum	2430.00	6.35	0.01114	
Revenues	$639,090.00	$ 8,497,233.45	$ 7,858,822.17	$ 16,995,145.62

Original Unbundled Rate

	flat	per kW	per kWh		Dem. Rev. to Energy
Basic Delivery Service	2430.00	11.16	0.03288		
Revenues	$639,090.00	$ 14,933,720.52	$ 23,195,518.22	$ 38,768,328.74	39.17%

Calculation of New Discounted Standard Offer Rate (Discount of 1.5%)

Discounted Revenues				$ 38,186,803.81
Difference				$ 581,524.93
New Revenue Stream	$639,090.00	$ 14,705,960.12	$ 22,841,753.70	$ 38,186,803.81
SO Discounted Rates*	2430.00	10.99	0.03238	

Difference between Standard Offer and Direct Access rates

	flat	per kW	per kWh		
SO Discounted Rate	2430.00	10.99	0.03238		
Direct access	2430.00	6.35	0.01114		1999
Difference	**0.00**	**4.64**	**0.02124**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 6,208,726.67**	**$ 14,982,931.52**	**$ 21,191,658.19**	**0.0300**

Calculation of Average Bill Size

May - October	
Total kWh	319,405,200
Total kW	587,163
Bills	110
Avg. Bill kWh	2,903,684
Avg. Bill kW	5,338
November - April	
Total kWh	386,054,600
Total kW	750,984
Bills	153
Avg. Bill kWh	2,523,233
Avg. Bill kW	4,908
Annual	
Total kWh	705,459,800
Total kW	1,338,147
Bills	263
Avg. Bill kWh	2,682,357
Avg. Bill kW	5,088

Average transmission rate calculation		rates
$	966,480	0.00137
$	655,692	0.49
$	1,622,172	
	0.00230	

* Assume reduction flows through demand and energy charges.

Year 2 (2000)

2000 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		3.33	0.00943	
SBC			0.00115	
CTC		2.55		
Sum	2430.00	5.88	0.01058	
Revenues	$639,090.00	$ 7,868,304.36	$ 7,463,764.68	$ 15,971,159.04

Percentage impact of reduction in Distribution only

1999	$11,771,202	
2000	$11,108,515	
difference	$662,687	
	1.74%	of 1999 standard offer bill
	0.0009	apparent reduction in reg. Asset charge

Calculation of New Discounted Standard Offer Rate

Discounted Revenues				$ 37,614,001.76
Difference				$ 1,154,326.99
New Revenue Stream	$639,090.00	$ 14,253,855.72	$ 22,139,531.11	$ 37,032,476.82
SO Discounted Rates*	2430.00	10.65	0.03138	

Difference between standard offer & direct access

	flat	per kW	per kWh	TOTAL $	2000 per kWh	
SO Discounted Rate	2430.00	10.65	0.03138			
Direct Access	2430.00	5.88	0.01058			
Difference	**0.00**	**4.77**	**0.02080**			
Annual Generation Credit		**$ 6,385,551.36**	**$ 14,675,766.42**	**$ 21,061,317.78**	**0.0299**	-0.62%

Year 3 (2001)

2001 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		3.15	0.00892	
SBC			0.00115	
CTC		1.89		
Sum	2430.00	5.04	0.01007	
Revenues	$639,090.00	$ 6,744,260.88	$ 7,103,980.19	$ 14,487,331.07

Percentage impact of reduction in Distribution only

2000	11,108,515.42	
2001	10,507,864.47	
difference	600,650.96	
	1.57%	of 1999 standard offer
	0.0009	apparent reduction in reg. Asset charge

Calculation of New Discounted Standard Offer Rate

Discounted Revenues				$ 37,143,826.73
Difference				$ 1,624,502.01
New Revenue Stream	$639,090.00	$ 14,297,467.09	$ 22,207,269.65	$ 37,143,826.73
SO Discounted Rates*	2430.00	10.68	0.03148	

Difference between standard offer and direct access rates

	flat	per kW	per kWh	TOTAL $	2001 per kWh
SO Discounted Rate	2430.00	10.68	0.03148		
Direct Access	2430.00	5.04	0.01007		
Difference	**0.00**	**5.64**	**0.02141**		
Annual Generation Credit		**$ 7,553,206.21**	**$ 15,103,289.46**	**$ 22,656,495.67**	**0.0321**

* Assume reduction flows through demand and energy charges.

Year 4 (2002)

2002 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		2.98	0.00845	
SBC			0.00115	
CTC		1.72		
Sum	2430.00	4.7	0.0096	
Revenues	$639,090.00	$ 6,289,290.90	$ 6,772,414.08	$ 13,700,794.98

2001	10,507,864.47	
2002	9,948,813.37	
difference	559,051.10	
	1.46%	of new standard offer 1999
	0.0008	apparent reduction in reg. Asset charge

Calculation of New Discounted Standard Offer Rate

Discounted Revenues				$ 36,865,248.03
Difference				$ 1,903,080.71
New Revenue Stream	$639,090.00	$ 14,188,358.79	$ 22,037,799.25	$ 36,865,248.03
SO Discounted Rates*	2430.00	10.60	0.03124	

Difference between Standard Offer and Direct Access rates

	flat	per kW	per kWh		
SO Discounted Rate	2430.00	10.60	0.03124		
Direct access rate	2430.00	4.7	0.0096		
Difference	**0.00**	**5.90**	**0.021638916**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 7,899,067.89**	**$ 15,265,385.17**	**$ 23,164,453.05**	**0.0328**

Year 5 (2003)

2003 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		2.83	0.00802	
SBC			0.00115	
CTC		1.51		
Sum	2430.00	4.34	0.00917	
Revenues	$639,090.00	$ 5,807,557.98	$ 6,469,066.37	$ 12,915,714.35

2001	2,301,612.84	
2002	9,444,743.61	
difference	(7,143,130.77)	
	-18.71%	of new standard offer 1999
	(0.0101)	apparent reduction in reg. Asset charge

Calculation of New Discounted Standard Offer Rate

Revenues (no further discount)				$ 36,865,248.03
Difference				$ 1,903,080.71
New Revenue Stream	$639,090.00	$ 14,188,358.79	$ 22,037,799.25	$ 36,865,248.03
SO Discounted Rates*	2430.00	10.60	0.03124	

Difference between Standard Offer and Direct Access rates

	flat	per kW	per kWh		
SO Discounted Rate	2430.00	10.60	0.03124		
Direct access rate	2430.00	4.34	0.00917		
Difference	**0.00**	**6.26**	**0.022068916**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 8,380,800.81**	**$ 15,568,732.88**	**$ 23,949,533.69**	**0.0339**

* Assume reduction flows through demand and energy charges.

Year 6 (2004)

2003 Direct Access Delivery Rates

	flat	per kW	per kWh	
Basic Delivery Service	2430.00			
Distribution		2.73	0.00774	
SBC			0.00115	
CTC		1.09		
Sum	2430.00	3.82	0.00889	
Revenues	$639,090.00	$ 5,111,721.54	$ 6,271,537.62	$ 12,022,349.16

Calculation of New Discounted Standard Offer Rate

Revenues (no further discount)				$ 36,865,248.03
Difference				$ 1,903,080.71
New Revenue Stream	$639,090.00	$ 14,188,358.79	$ 22,037,799.25	$ 36,865,248.03
SO Discounted Rates*	2430.00	10.60	0.03124	

Difference between Standard Offer and Direct Access rates

	flat	per kW	per kWh		
SO Discounted Rate	2430.00	10.60	0.03124		
Direct access rate	2430.00	3.82	0.00889		
Difference	**0.00**	**6.78**	**0.022348916**	**TOTAL $**	**per kWh**
Annual Generation Credit		**$ 9,076,637.25**	**$ 15,766,261.62**	**$ 24,842,898.87**	**0.0352**

* Assume reduction flows through demand and energy charges.

CALCULATION OF RELEVANT WHOLESALE MARKET PRICES

There is a "day ahead" spot market in California, that indicates the spot price of energy for every hour in the last year and more. This reflects price bids from generators for the next day and bids to purchase for the next day from buyers. The California market reports the spot price for the Palo Verde zone, which is where power is bought and sold for Arizona. This market is still "thin", meaning that the volume of trades is not very large, but it is the best indicator we have of wholesale trades. There will also be bilateral sales and purchases, but the terms and prices of these trades are seldom public information.

Spot hourly prices vary a great deal - a typical summer midday price will be a multiple of a winter evening price. We weighted the Palo Verde price by the California Power Exchange hourly load, which is available electronically. We rejected results for June of 1998. This was only the third month in which trading had been occurring, and the unweighted average price was so low compared to preceding and all succeeding months as to be viewed as an anomaly. The average weighted price for the last eleven months was 28.06 cents. However, Arizona load varies more seasonally than does California. In addition, the 1998 summer was milder than normal, which will tend to reduce average prices and also peak loads. We increased the California load weighted price to 2.9 cents per kWh to account for these factors. If wholesale prices are weighted for each customer group, to reflect different use patterns, we would expect that Extra-Large General Service would be somewhat lower than the average Arizona value, while General Service and Residential weighted wholesale prices would be higher than the average.

To get power to the customer will also require accounting for line losses, which increases the price from 5 percent to 7 percent, depending on the customer's voltage level, or 1.4 mills for Extra-Large General Service customers. In addition, the supplier will be required to acquire ancillary services. Initially, all suppliers may buy all of these services from APS. Based on APS' Open Access Transmission Tariff, the cost of these required services is about .1 cent per kWh.

Finally, and most significantly, the Direct Access Rates do not provide for transmission to the customer. APS will charge separately for this essential part of service. Mr. Higgins states that he has seen the rates that APS will charge; the Commission and customers have not. I have used the unbundled transmission costs by class based on APS' unbundled rates in the November Settlement rates, which ranged from 2 to 4 mills per kWh. The minimum cost[1] for a retail customer to have purchased all energy needs from the California spot market, with minimum transmission costs and paying APS only for ancillary services, would be at least 3.2 cents per kWh for the Extra-Large General Service class.

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[1] There are no transmission charges other than from APS in this price.

ESTIMATION OF RETAIL GENERATION PRICE

First, customers, or their suppliers, will not project their load exactly, which means they will have to pay APS for "load balancing" i.e. when they have ordered slightly less or more energy than their actual load, they have to pay for the difference between their projected load and their actual load. This service will probably cost about 1 mill on average. Second, there is risk to the customer from purchasing from the spot market. If a supplier must quote a price to customers, the supplier will take the risk and must charge for it. If the customer is willing to take the risk, there is still a value that the customer will place on that risk. If the customer absolutely knew that the Company would charge 3 cents for the next year, and only expected that the market price would be 3 cents for the same period, the wise customer would choose the Company supply to eliminate this risk. Third, the supplier has costs associated with customer contact, and estimating the customer load. The Company includes these costs in its distribution costs and does not have to charge for them, but a supplier will. Fourth, a supplier will need to make some profit. If the supplier sells the product at exactly what he paid for it, he won't stay in existence very long. The Company makes a profit when it sells generation, but this profit is reflected in a return on its generating plants. Below I present a conservative estimate that builds a minimum retail price from the wholesale price of these costs.

ESTIMATE OF RETAIL MARKET PRICE

	Residential	General Service	Extra Large GS
Price of predicted load			
Spot wholesale price	3.10	3.00	2.70
Line loss factor	7.00%	7.00%	5.00%
Cost of line losses	0.22	0.21	0.14
Transmission cost	0.40	0.34	0.20
Cost of ancillary ser vices	0.10	0.10	0.10
Cost at customer level	3.82	3.65	3.14
Additional retail costs			
Balancing load & energy	0.15	0.12	0.10
Marketer costs	0.60	0.40	0.15
Retail price	4.57	4.17	3.39